at other sites could leach arsenic at higher levels if arsenic were not attenuated by surrounding soils or diluted before reaching drinking water.

The results discussed above indicate that the fixated FGD/fly ash wastes have been, and will continue to be, a source of contamination at the site. Because exceedances for many contaminants were probably due to concurrent contamination from acid mine drainage, leachate from coal combustion waste may have only a small incremental impact on water quality.

- The Dave Johnston plant in Wyoming is located in an arid region with little ground-water recharge. The plant is the oldest of the six sites, and burns low-sulfur western coal. There are a number of disposal areas at the site; the ADL study investigated two unlined fly ash landfills, one active and one closed. Exceedances of the Primary Drinking Water Standards for cadmium (up to 3 times the PDWS) were found in ground water upgradient and downgradient of the site. Cadmium was found at elevated concentrations in pond liquors and ground water beneath the wastes. Exceedances of Secondary Drinking Water Standards for manganese and sulfate were also observed in downgradient and upgradient ground water. These two contaminants and boron were found in elevated concentrations in ground water beneath the waste and in pond liquors. No samples were analyzed for the presence of arsenic in the pond liquors. Chemical attenuation by soils at the site was found to be low for trace metals such as arsenic.Interpretations of the sampling results were difficult to make because other potential contamination sources exist, such as other waste disposal areas at the site (the location and ages of which are uncertain) and contaminants naturally occurring in the soil, which is highly mineralized around the Johnston site; and uncertainties with regard to what degree leachate from the two landfills had reached the downgradient wells. Contamination from the site could possibly increase until steady-state concentrations are reached.

- The Sherburne County Plant in central Minnesota disposed of fly ash and FGD waste in one clay-lined pond and bottom ash in an adjacent clay-lined pond. Exceedances of the Primary Drinking Water Standards were observed in both upgradient and downgradient ground water for cadmium (up to 2 times the PDWS for both) and for nitrate, and in downgradient ground water for chromium (up to 1.2 times the PDWS). Pond liquors were found to exhibit high concentrations of several constituents, including cadmium (up to 30 times the PDWS), chromium (up to 16 times the PDWS), fluoride, nitrate, lead (up to 28 times the PDWS), and selenium (up to 25 times the PDWS). While the pond liquors exhibited high concentrations of contaminants, leachate from these wastes did not appear to have migrated into and mixed with ground water to a great extent. Ground-water samples collected at the site seemed to indicate that a few constituents (sulfate and boron) had migrated from the wastes, but not at levels exceeding SDWS. The clay liner appeared to have significantly reduced the rate of release of leachate from the disposal ponds, precluding the development of elevated trace metal concentrations at downgradient wells. Over time, downgradient wells will likely show increased levels of contamination, since steady-state conditions had not been achieved between leachate from the landfill and the ground water. Without the clay liner, the leachate seepage rate would probably have been much greater. Since the surrounding soils may not chemically attenuate selenium, this contaminant might cause PDWS exceedances once steady-state concentrations in ground water are reached.

- The Powerton Plant disposed fly ash, bottom ash, and slag in an older landfill approximately one mile south of the site. In a newer portion of the landfill, disposal operations consisted of disposing intermixed fly ash and slag. The newer landfill and part of the older one are underlain by a liner consisting of ash and lime. The downgradient ground-water wells exhibited levels of cadmium up to three times the Primary Drinking Water Standard and, in one sample, lead at four times the PDWS. An upgradient well, located on the border of the landfill wastes, exhibited a concentration of cadmium at the level of the Primary Drinking Water Standard. Secondary Drinking Water Standards for iron, manganese, and sulfate were exceeded in downgradient wells, and for manganese in an upgradient well (but at a level of exceedance lower than the downgradient measurements). These results indicate that leaching and migration of ash wastes had occurred at the site, but it was difficult to determine the effect the leachate had, or will have, on ground-water quality. Dilution and chemical attenuation may have prevented the buildup at downgradient locations of significant concentrations of trace metals such as arsenic and selenium. The degree to which Lost Creek, a nearby downgradient stream, was diluting waste constituents that reach it may be significant.

- The Lansing Smith plant in southern Florida disposed a mixture of fly ash and bottom ash in an unlined disposal pond located in a coastal area. Concentrations greater than the Primary Drinking Water Standards were observed for cadmium (up to five times the PDWS), chromium (up to four times the PDWS), and fluoride in the downgradient ground water at the site and, with the possible exception of fluoride, appeared to be due largely to the leaching of the ponded ash wastes. Exceedances of Secondary Drinking Water Standards for sulfate, chloride, manganese, and iron were also observed in downgradient ground water. However, most of these contaminants are seawater-related and their reported concentrations appeared to be influenced by the use of seawater in plant operations and infiltration of estuarine (saline) water at the site. The leachate generated migrates to a shallow, unused, tidal aquifer. These results indicate that ash disposal at this site appears to have had a measurable impact on ground-water quality. Health risks at this particular site, however, were probably minimal since the ground water and surface water were not used as a source of drinking water.

5.2.1.1 Ground-water Sampling

Exhibits 5-10 and 5-11 summarize the results of the ADL ground-water quality data at the six disposal sites for constituents with established Primary and Secondary Drinking Water Standards, respectively. As can be seen from Exhibit 5-10:

- One site had no exceedances of PDWS constituents, either upgradient or downgradient.
- One site had PDWS exceedances for cadmium only, with the same maximum PDWS exceedance upgradient and downgradient.
- One site had downgradient PDWS exceedances for cadmium, chromium, and nitrate, but for cadmium and nitrate the upgradient exceedances were at least as large as the downgradient exceedances. There were no upgradient exceedances of chromium; the one downgradient exceedance was 1.2 times PDWS.
- The three remaining sites had downgradient PDWS exceedances for cadmium that were more frequent and larger than upgradient exceedances. The largest downgradient exceedance for cadmium at any of the six sites was 20 times the PDWS.
- There were no upgradient chromium exceedances and only three exceedances out of 94 downgradient observations. Two of the downgradient exceedances were 1.2 times the PDWS and one was 4 times the PDWS. These three exceedances were at three different sites.

EXHIBIT 5-10

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER QUALITY DATA ON PRIMARY DRINKING WATER EXCEEDANCES

Units = ppm		Allen Site				New Elrama Site				Dave Johnston Site			
PDWS		1/ Downgradient (11 wells)		1/ Upgradient (1 well)		1/ Downgradient (5 wells)		1/ Upgradient (1 well)		1/ Downgradient (3 wells)		1/ Upgradient (2 wells)	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Arsenic (liq.)	0.05	0/12		0/2		0/1		0/2		0/2		0/3	
Barium	1	0/31		0/3		0/19		0/4		0/9		0/6	
Cadmium	0.01	0/31		0/3		3/19	20	0/4		6/9	3	3/6	3
Chromium (Cr VI)	0.05	0/31		0/3		1/19	1.2	0/4		0/9		0/6	
Fluoride	4.0	0/34		0/4		0/21		0/4		0/12		0/8	
Lead	0.05	0/31		0/3		0/19		0/4		0/9		0/6	
Mercury	0.002	0/0		0/0		0/0		0/0		0/0		0/0	
Nitrate 5/	45	0/34		0/4		0/20		0/4		0/12		0/8	
Selenium (liq.)	0.1	0/5		0/2		0/1		0/2		0/2		0/3	
Silver	0.05	0/31		0/3		0/19		0/4		0/9		0/9	

1/ For specific site descriptions, including lists and maps of wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant.

5/ The PDWS for nitrate measured as N is 10 ppm.

EXHIBIT 5-10 (Continued)

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER QUALITY DATA ON PRIMARY DRINKING WATER EXCEEDANCES

Units = ppm		Sherburne County Site				Powerton Station Site				Lansing Smith Steam Plant			
PDWS		Downgradient 1/ (3 wells)		Upgradient 1/ (2 wells)		Downgradient 1/ (3 wells)		Upgradient 1/ (1 well)		Downgradient 1/ (5 wells)		Upgradient 1/ (3 wells)	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Arsenic (liq.)	0.05	0/3		0/3		0/8		0/2		0/5		0/4	
Barium	1	0/12		0/8		0/9		0/4		0/14		0/6	
Cadmium	0.01	2/12	2	2/8	2	8/9	3	2/4	1	10/14	5	2/6	2
Chromium (Cr VI)	0.05	1/12	1.2	0/8		0/9		0/4		1/14	4	0/6	
Fluoride	4.0	0/12		0/8		0/9		0/4		5/14	13.5	0/6	
Lead	0.05	0/12		0/8		1/9	4	0/4		0/14		0/6	
Mercury	0.002	0/0		0/0		0/0		0/0		0/0		0/0	
Nitrate 5/	45	2/12	1.1	2/8	27	0/9		2/4	1.1	0/0		0/0	
Selenium (liq.)	0.1	0/3		0/3		0/8		0/2		0/5		0/4	
Silver	0.05	0/12		0/8		0/9		0/4		0/14		0/6	

1/ For specific site descriptions, including lists and maps of wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant.

5/ The PDWS for nitrate measured as N is 10 ppm.

EXHIBIT 5-11

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER QUALITY DATA ON SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm		Allen Site				New Elrama Site				Dave Johnston Site			
SDWS		Downgradient 1/ (11 wells)		Upgradient 1/ (1 well)		Downgradient 1/ (5 wells)		Upgradient 1/ (1 well)		Downgradient 1/ (3 wells)		Upgradient 1/ (2 wells)	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Chloride	250	0/34		0/4		0/21		0/4		0/12		0/8	
Copper	1	0/31		0/3		0/19		0/4		0/9		0/6	
Iron	0.3	7/31	82	0/3		0/19		1/4	1.8	0/9		0/6	
Manganese	0.05	19/31	102	1/3	1.4	19/19	456	4/4	197	1/9	3.2	1/6	4.6
Sulfate	250	0/34		0/3		9/19	4.7	3/4	1.5	12/12	5.8	4/8	5.1
Zinc	5	0/31		0/3		0/19		0/4		0/9		0/6	
pH Lab 5/	<=6.5	10/10	4.7	1/1	5.9	0/0		0/0		0/0		0/0	
	>=8.5	0/10		0/1		0/0		0/0		0/0		0/0	
pH Field 5/	<=6.5	21/28	4.4	2/3	6.2	9/14	5.2	2/2	4.5	0/9		0/6	
	>=8.5	0/28		0/3		0/14		0/2		0/9		0/6	

1/ For specific site descriptions, including lists and maps of the wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.

5/ As indicated in footnote 15, the Max. Exceed column for the reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

EXHIBIT 5-11 (Continued)

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER QUALITY DATA ON SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm		Sherburne County Site				Powerton Station Site				Lansing Smith Steam Plant			
	SDWS	Downgradient 1/ (3 wells)		Upgradient 1/ (2 wells)		Downgradient 1/ (3 wells)		Upgradient 1/ (1 well)		Downgradient 1/ (5 wells)		Upgradient 1/ (3 wells)	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Chloride	250	0/12		0/8		0/9		0/4		14/14	22.4	0/6	
Copper	1	0/12		0/8		0/9		0/4		0/14		0/6	
Iron	0.3	0/12		1/8	1.9	4/9	42	0/4		14/14	118	6/6	37
Manganese	0.05	2/12	22	1/8	1.4	9/9	194	2/4	11	13/14	17.2	2/6	1.4
Sulfate	250	0/12		0/8		6/9	2.7	0/4		8/14	8.4	0/6	
Zinc	5	0/12		0/8		0/9		0/4		0/14		0/6	
pH Lab 5/	<=6.5	0/0		0/0		0/0		0/0		4/6	4.4	1/2	6.5
	>=8.5	0/0		0/0		0/0		0/0		0/6		0/2	
pH Field 5/	<=6.5	0/8		0/6		1/9	6	0/3		10/13	2.9	4/6	6
	>=8.5	0/8		0/6		0/9		0/3		0/13		0/6	

1/ For specific site descriptions, including lists and maps of the wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.

5/ As indicated in footnote 15, the Max. Exceed column for the reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

- One site had downgradient PDWS exceedances for fluoride in 5 of 14 samples. The maximum exceedance was 13.5 times the PDWS. There were no upgradient PDWS exceedances for fluoride at any of the six sites.

- There were no lead exceedances upgradient and only one PDWS exceedance out of 94 downgradient observations at 4 times the PDWS.

- The contaminants of most concern at the six sites appear to be cadmium and, to a lesser extent, chromium. For both of these contaminants, three sites had exceedances of the PDWS in downgradient ground water at levels higher than were found in upgradient ground water.

For constituents for which there are Secondary Drinking Water Standards, exceedances in downgradient ground water generally were higher than levels observed in upgradient wells. Results are shown in Exhibit 5-11.

5.2.1.2 Surface Water Sampling

Exhibit 5-12 summarizes the results of surface-water quality data obtained by ADL at background, peripheral, and downstream locations at three of the study sites -- Elrama, Powerton, and Lansing Smith -- for constituents with established Primary and Secondary Drinking Water Standards. Examination of these results for PDWS constituents indicates that:

- At the Lansing Smith site, downgradient and peripheral surface water samples showed cadmium concentrations up to 5 times the PDWS, chromium concentrations up to 1.2 times the PDWS, and fluoride concentrations up to 20 times the PDWS. No upgradient samples were collected at the Lansing Smith site.

- Exceedances were found for cadmium (up to 2 times the PDWS) and nitrate (up to 1.2 times the PDWS) in both upgradient and downgradient surface water at the Powerton site. The exceedances were similar in upgradient and downgradient samples both in terms of the proportion of samples in which exceedances were found and the magnitude of the exceedances.

EXHIBIT 5-12

SUMMARY OF ARTHUR D. LITTLE'S SURFACE-WATER QUALITY DATA ON PRIMARY AND SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm		New Elrama Site				Powerton Station Site				Lansing Smith Steam Plant					
PDWS		Downgradient (4 stations) 1/		Upgradient (1 station) 1/		Downgradient (1 station) 1/		Upgradient (3 stations) 1/		Downgradient (6 stations) 1/		Peripheral (3 stations) 1/		Downgradient Saline (2 stations) 1/	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Arsenic (liq.)	0.05	0/1		0/1		0/1		0/2		0/2		0/1		0/3	
Barium	1	0/7		0/3		0/3		0/8		0/13		0/8		0/5	
Cadmium	0.01	0/7		0/3		2/3	2	5/8	2	10/13	5	4/8	4	5/5	4
Chromium (Cr VI)	0.05	0/7		0/3		0/3		0/8		0/13		0/8		1/5	1.2
Fluoride	4.0	0/7		0/3		0/3		0/8		5/13	6.5	2/8	2	2/5	20
Lead	0.05	0/7		0/3		0/3		0/8		0/13		0/8		0/5	
Mercury	0.002	0/0		0/0		0/0		0/0		0/0		0/0		0/0	
Nitrate 5/	45	0/7		0/3		1/3	1.1	3/7	1.2	0/0		0/0		0/0	
Selenium (liq.)	0.1	0/1		0/1		0/1		0/2		0/2		0/1		0/3	
Silver	0.05	0/7		0/3		0/3		0/8		0/13		0/8		0/5	

1/ For specific site descriptions, including lists and maps of the stations used for data, see Appendix E. Peripheral stations are neither upgradient nor downgradient of the site. These stations are located across the gradient from the site, and may become contaminated by lateral dispersion of waste constituents.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant.

5/ The PDWS for nitrate measured as N is 10 ppm.

EXHIBIT 5-12 (Continued)

SUMMARY OF ARTHUR D. LITTLE'S SURFACE-WATER QUALITY DATA ON PRIMARY AND SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm		New Elrama Site				Powerton Station Site				Lansing Smith Steam Plant					
	SDWS	1/ Downgradient (4 stations)		1/ Upgradient (1 station)		1/ Downgradient (1 station)		1/ Upgradient (3 stations)		1/ Downgradient (6 stations)		1/ Peripheral (3 stations)		1/ Downgradient Saline (2 stations)	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Chloride	250	0/7		0/3		0/3		0/8		13/13	11.9	5/8	10	5/5	58
Copper	1	0/7		0/3		0/3		0/8		0/13		0/8		0/5	
Iron	0.3	0/7		0/3		0/3		0/8		11/13	370	6/8	34	0/5	
Manganese	0.05	7/7	7.4	3/3	4.2	2/3	2.2	2/8	1	11/13	64	6/8	4.8	0/5	
Sulfate	250	0/7		0/3		0/3		0/8		12/13	7.5	4/8	3.4	5/5	9.9
Zinc	5	0/7		0/3		0/3		0/8		0/13		0/8		0/5	
pH Lab 5/	<=6.5	0/0		0/0		0/0		0/0		5/6	3.3	2/3	3.8	0/1	
	>=8.5	0/0		0/0		0/0		0/0		0/6		0/3		0/1	
pH Field 5/	<=6.5	4/7	6.1	2/3	6	0/3		0/8		5/10	4.1	4/7	3.4	0/5	
	>=8.5	0/7		0/3		1/3	8.5	2/8	8.5	0/10		0/7		0/5	

1/ For specific site descriptions, including lists and maps of the stations used for data, see Appendix E. Peripheral stations are neither upgradient nor downgradient of the site. These stations are located across the gradient from the site, and may becom contaminated by lateral dispersion of waste constituents.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.

5/ As indicated in footnote 10, the Max. Exceed. column for reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

- No exceedances of PDWS were found upgradient or downgradient at the Elrama site, although there had been downgradient exceedances at Elrama in ground water for cadmium and chromium.

5.2.1.3 Waste Fluid Sampling

In addition to ground-water monitoring, waste fluid samples were collected from the waste ponds at the Allen, Sherburne County, and Lansing Smith sites, and from dry fly ash landfills at the Dave Johnston site. Water from within and beneath FGD sludge and fly ash waste mixtures were collected from the Elrama landfill. No waste fluid samples were obtained at the Powerton site. Key observations are presented below.

- Arsenic was present in the waste fluids at elevated concentrations (up to 31 times the Primary Drinking Water Standard) at two of the five sites sampled. At these sites (Allen and Elrama), arsenic may be attenuated by soils at the site; attenuation tests indicate the soils had a moderate to high attenuation capacity, and no exceedances for arsenic were observed in ground water at the sites. The Dave Johnston site was the only disposal area where soils were found to have low attenuation capacities for arsenic; however, there are no data pertaining to waste fluids at this site, and exceedances for arsenic in the ground water were not observed. These results indicate that, depending on the coal source, arsenic may occur at elevated concentrations in waste fluids, but can be attenuated by soils within and surrounding a coal combustion waste disposal site. If the soils at a disposal site have low attenuation capacities for arsenic, this element may be of concern with regard to ground water and surface water contamination.

- Cadmium is present at elevated concentrations (up to 30 times the Primary Drinking Water Standard) in the waste fluids at all five sites. At Powerton, although no waste fluid samples were taken, ground-water samples obtained from directly beneath the wastes also exhibited elevated concentrations of cadmium. These results support the conclusion that elevated concentrations of cadmium observed in downgradient ground water may be attributable to coal combustion wastes.

- Chromium is present at elevated concentrations (up to 21 times the Primary Drinking Water Standard) in the waste fluids at two of the five sites. At these sites, higher chromium concentrations were found in downgradient ground water than were found in upgradient ground water. These observations suggest that ground-water contamination by chromium at these two study sites may be attributable to the coal combustion wastes. At a third site at which downgradient exceedances of chromium in ground water were observed, waste fluid samples were mixed with ground water occurring beneath the wastes during collection, which may account for lower waste fluid concentrations at this site.

- Other constituents that were found at elevated concentrations within the waste fluids include fluoride at all five sites (up to 10 times the PDWS); lead at one of five sites (up to 28 times the PDWS); nitrate at one of five sites (up to 7 times the PDWS); and selenium at one of four sites (up to 25 times the PDWS).

- Constituents for which Secondary Drinking Water Standards are established were found at the following elevated concentrations: chloride at three of five sites (up to 61 times the SDWS); iron at two of five sites (up to 221 times the SDWS); manganese at four of five sites (up to 466 times the SDWS); and sulfate at four of five sites (up to 42 times the SDWS). Exceedances of pH standards were found in the waste fluids at two of three sites tested. At these two sites, both acidic (as low as pH 5.9) and alkaline (as high as pH 11) conditions were found to exist. Average pH values measured in these waste fluids indicated that they were generally alkaline.

- Results of waste fluid sampling at the Sherburne County site showed exceedances of Primary Drinking Water Standards for cadmium (up to 30 times PDWS); chromium (up to 16 times the PDWS); fluoride (up to 13 times the PDWS); lead (up to 28 times the PDWS); nitrates (up to 6.9 times the PDWS); and selenium (up to 25 times the PDWS). Measurements also showed maximum exceedances of Secondary Drinking Water Standards for chloride (up to 1.9 times the SDWS); iron (up to 6.1 times the SDWS); manganese (up to 316 times the SDWS); and sulfate (up to 42 times the SDWS). This was the only site where disposal areas or ponds were completely lined. The clay liner appeared to have reduced the release of leachate, thereby concentrating waste constituents.

Results from waste fluid studies conducted by other organizations are described in Appendix D.

5.2.1.4 Summary

Results from the Arthur D. Little study suggest that under the waste management procedures used by the facilities studied, some coal combustion waste leachate was migrating into ground water beneath and downgradient from disposal sites. Five sites had concentrations of cadmium in downgradient ground water that exceeded the PDWS. Two of these five had maximum upgradient exceedances at the same level as the maximum downgradient exceedance, and two of the sites had upgradient concentrations that were equal to or above the PDWS, although the maximum concentration was less than the downgradient concentrations. One of the five sites had upgradient measurements of cadmium that were below the PDWS. Exceedances of chromium were detected in a few ground-water samples downgradient of three sites; there were no chromium concentrations above the PDWS in the upgradient ground water of any site. There were no detected exceedances of arsenic, barium, mercury, selenium, or silver in the ground water or surface water at any of the six sites. In total, approximately 5 percent of the downgradient observations exceeded the PDWS.

5.2.2 Franklin Associates Survey of State Ground-Water Data

EPA commissioned Franklin Associates to gather data from state regulatory agencies on the quality of ground water at or near coal-fired electric utility fly ash disposal sites.[23] The objective of this survey was to determine the level of ground-water contamination in the vicinity of disposal sites. However, according to the Franklin Associates report: "No attempt was made to determine what monitoring wells might be up gradient, or what wells might be down gradient, or even as to whether specific ash disposal sites were in fact contributing specific pollutants."

Franklin Associates contacted 44 states in which coal-fired facilities were located; of these 44 states, 13 provided data. The data base that was developed included data from more than 4700 well samples taken from 66 sites.

Analysis of these samples revealed 1129 exceedances of the PDWS out of more than 15,000 observations, as shown in Exhibit 5-13. Ninety-two percent of the exceedances were less than ten times the PDWS; eight of the exceedances were 100 times greater than the PDWS.

There were 5952 exceedances of the SDWS out of nearly 20,000 observations as shown in Exhibit 5-14. These secondary standards were exceeded more frequently than the primary standards, and exceedances were usually greater. For example, about 77 percent of the SDWS exceedances were less than 10 times the standard (compared with 92 percent for PDWS exceedances), whereas 4 percent of the exceedances were greater than 100 times the SDWS (compared with less than one percent for PDWS exceedances).

Since this study did not compare upgradient and downgradient concentrations, it is not possible to determine whether occurrences of contamination at particular sites are the result of utility waste disposal practices or background levels of contaminants.

EXHIBIT 5-13

SUMMARY OF PDWS EXCEEDANCES IN THE FRANKLIN ASSOCIATES SURVEY

Constituent	Total Observations	Number of Observations Exceeding PDWS By 1 X	10 X	100 X	Highest Exceedance (X PDWS)
Arsenic	1995	94	0	0	9.8
Barium	1353	108	9	0	44.0
Cadmium	1733	126	16	1	531.0
Chromium	1863	92	5	0	50.2
Fluoride	995	28	3	0	19.3
Lead	1722	243	20	1	182.0
Mercury	1282	30	8	5	500.0
Nitrate	1432	204	0	0	7.3
Selenium	2453	196	30	1	100.0
Silver	530	8	0	0	8.0
TOTAL	15,358	1129	81	8	

Source: Franklin Associates, Ltd., Summary of Ground-water Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for the U.S. Environmental Protection Agency, March 1984.

EXHIBIT 5-14

SUMMARY OF SDWS EXCEEDANCES IN THE FRANKLIN ASSOCIATES SURVEY

Constituent	Total Observations	Number of Observations Exceeding SDWS By 1 X	10 X	100 X	Highest Exceedance (X SDWS)
Chloride	2921	109	14	0	42.0
Copper	650	1	0	0	1.2
Iron	3140	1942	862	149	4,000.0
Manganese	1673	1050	467	80	2,400.0
pH	4107	843	-	-	-
Sulfate	4378	1059	13	0	23.2
TDS	1925	920	24	0	28.7
Zinc	1175	28	4	0	46.0
TOTAL	19,969	5952	1384	229	

Source: Franklin Associates, Ltd., Summary of Ground-water Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for the U.S. Environmental Protection Agency, March 1984.

5.2.3 Envirosphere Ground-Water Survey

In response to the temporary exemption of utility wastes from regulation under Subtitle C of RCRA, the Utility Solid Waste Activities Group (USWAG) commissioned Envirosphere, Inc., to review information available from electric utilities on the quality of ground water at utility waste disposal sites.[24] Envirosphere solicited information from 98 utilities on the number and type of constituents they monitored, the frequency with which measurements were taken, and the period of time for which they had collected ground-water monitoring data. Ninety-six of the contacted utilities responded to the request for information. From these 96 utilities, Envirosphere selected for further study those that appeared to have adequate data on ground-water quality. These utilities were contacted and asked to provide their available data for use in Envirosphere's study. The participating utilities (the exact number of utilities was not provided) forwarded the requested information to Envirosphere on the 28 disposal facilities they operated. The utilities chose to withdraw three of the 28 disposal sites from the study subsequent to the analysis of the data, leaving 25 disposal sites in the data pool.

In order to analyze the data, Envirosphere paired the measurements taken at upgradient and downgradient wells at approximately the same time and in the same aquifer.[25] These data were then compared to the applicable drinking water standards to determine whether the standards had been exceeded. Two disposal sites were then eliminated from further consideration because no upgradient wells could be identified. The remaining 23 disposal sites produced a total of 9,528 paired measurements of upgradient and downgradient ground-water concentrations.

Exhibit 5-15 summarizes the information from the Envirosphere data base for those cases where the Primary Drinking Water Standards (PDWS) were exceeded by the downgradient measurement. The most obvious indication that a waste facility is contributing to a PDWS exceedance is a measurement indicating downgradient values higher than the PDWS and upgradient values lower than the PDWS. According to Envirosphere's report, about 1.7 percent of the data fell into this category.[26] For those cases in which both the upgradient and downgradient values were exceeded, Envirosphere argued that it was difficult to attribute the exceedances to the disposal facility without further site-specific analysis. About 5 percent of the measurements fell into this category, with 60 percent of these indicating upgradient values equal to or greater than the downgradient values.

Maximum concentrations of several substances significantly exceeded the PDWS in downgradient wells: arsenic, 560 times the PDWS; lead, 480 times the PDWS; mercury, 235 times the PDWS, and selenium, 100 times the PDWS. These values must be compared to the maximum upgradient reading since some of the contamination may be unrelated to the disposal facility. As shown in Exhibit 5-15, the downgradient concentration was sometimes higher than the upgradient value even when the upgradient value exceeded the PDWS. However, exceedances of the magnitudes shown in Exhibit 5-15 comprised a small fraction of the total measurements in the Envirosphere data base.

The Envirosphere data also included information regarding exceedances of the Secondary Drinking Water Standards (SDWS). A summary of these data is shown in Exhibit 5-16. The data indicate that in 8.2 percent of the cases the

EXHIBIT 5-15

SUMMARY OF PDWS EXCEEDANCES IN ENVIROSPHERE'S GROUND-WATER DATA

		Downgradient Observations a/ Exceeding PDWS When:					
		Upgradient Does Not Exceed		Upgradient Exceeds		Maximum Downgradient Observation (X PDWS) b/	
Constituent	Total Observations	Number	%	Number	%		
Arsenic	588	7	1	0	0	560	(192)
Barium	298	0	0	0	0	1	(3)
Cadmium	571	59	10	9	2	6	(1)
Chromium	658	20	3	10	2	20	(76)
Lead	639	29	5	67	10	480	(220)
Mercury	575	8	1	2	c/	235	(9)
Selenium	489	5	1	34	7	100	(100)
Silver	261	0	0	0	0	1	(0.2)
TOTAL	4079	128	3 d/	122	3 d/		

a/ Envirosphere classified measurements by comparing downgradient values with upgradient values. When the downgradient value exceeded the PDWS, classification depended on whether the upgradient value also exceeded the PDWS. Both categories of measurements are shown here, although Envirosphere focused primarily on pairs of measurements in which the downgradient value exceeded the PDWS but the upgradient value did not.

b/ Maximum downgradient value observed in the Envirosphere data base. The corresponding paired upgradient concentrations are not available. The maximum upgradient value of all measurements at the same facility is shown in parentheses.

c/ Less than 0.5 percent.

d/ These percentages apply to the total number of observations. Envirosphere "normalized" the data to correct for sites that had a high proportion of data points so that one site would not be overly represented; these normalized values are noted in the text of the report.

Source: Envirosphere Company, "Report on the Ground-water Data Base Assembled by the Utility Solid Waste Activities Group," in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix C.

EXHIBIT 5-16

SUMMARY OF SDWS EXCEEDANCES IN ENVIROSPHERE'S GROUND-WATER DATA

		Downgradient Observations a/ Exceeding SDWS When:				Maximum Downgradient Observation (X SDWS) b/	
		Upgradient Does Not Exceed		Upgradient Exceeds			
Constituent	Total Observations	Number	%	Number	%		
Chloride	502	4	1	7	1	22	(5)
Copper	452	9	2	0	0	2	(0.02)
Iron	964	60	6	376	39	3458	(2)
Manganese	487	157	32	143	29	474	(5)
Sulfate	1028	289	28	57	6	32	(8)
Total Dissolved Solids	908	159	18	292	32	31	(2)
Zinc	387	3	1	3	1	1	(0.1)
TOTAL	4728	681	14 c/	875	19 c/		

a/ Envirosphere classified measurements by comparing downgradient values with upgradient values. When the downgradient value exceeded the SDWS, classification depended on whether the upgradient value also exceeded the SDWS. Both categories of measurements are shown here, although Envirosphere focused primarily on pairs of measurements in which the downgradient value exceeded the SDWS but the upgradient value did not.

b/ Maximum downgradient value observed in the Envirosphere data base. The corresponding (paired) upgradient concentrations are not available. The maximum upgradient value of all measurements at the same facility is shown in parentheses.

c/ These percentages apply to the total number of observations. Envirosphere "normalized" the data to correct for sites that had a high proportion of data points so that one site would not be overly represented; these normalized values are noted in the text of the report.

Source: Envirosphere Company, "Report on the Ground-water Data Base Assembled by the Utility Solid Waste Activities Group," in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix C.

downgradient value exceeded the SDWS while the upgradient value did not. In some cases the exceedances were substantially greater than the SDWS; e.g., the maximum observation for iron was 3458 times greater than the SDWS and manganese was 474 times greater.

In summary, the Envirosphere ground-water data show that Primary and Secondary Drinking Water Standards were exceeded in ground water downgradient from utility waste disposal facilities. However, the percentage of cases in which constituent concentrations in downgradient wells exceeded the standards when those in upgradient wells did not was small. There are limitations in the data, due in part to the way in which they were collected (e.g., only data from those utilities that voluntarily submitted data are included in the report). There is also a limited amount of information regarding the extent to which site-specific factors, such as environmental setting characteristics or other possible sources of contamination, could have had an effect on ground-water contamination.

5.2.4 Summary

The studies described in this section demonstrate that downgradient ground-water and surface-water concentrations exceeded the PDWS and SDWS for a few constituents. In some of these downgradient exceedances, corresponding upgradient exceedances also occurred, suggesting that the contamination was not necessarily caused by the waste disposal sites. For cases in which the downgradient ground water had constituent concentrations higher than the corresponding upgradient concentrations, the PDWS exceeded most often were those for cadmium, chromium, lead, and to a lesser extent, arsenic.

Some PDWS exceedances were quite high, e.g., up to 560 times for arsenic and 480 times for lead (see Exhibit 5-15). However, the frequency of PDWS exceedances for downgradient ground water and surface water is rather low. For example, 3.7 percent of the Envirosphere data had downgradient ground-water concentrations of PDWS higher than those measured in upgradient wells. Three of the six Arthur D. Little sites had downgradient ground water with concentrations of constituents that were both above the PDWS and above corresponding upgradient concentrations. Although the Arthur D. Little pond liquor data show high concentrations of PDWS and SDWS constituents, in most cases the constituents appeared to be contained within the disposal area or attenuated in the surrounding soils. This is particularly true for the case of arsenic, which was detected in the waste fluids at a level 31 times the PDWS, but was not found at elevated levels in ground water or surface water. There were no exceedances of arsenic, barium, mercury, selenium, or silver in downgradient ground water at any of the six Arthur D. Little sites. The Envirosphere study detected no exceedances of barium or silver.

5.3 EVIDENCE OF DAMAGE

This section examines documented cases in which danger to human health or the environment from surface runoff or leachate from the disposal of coal combustion wastes has been proved. The first part of this section reviews two major studies conducted for the Utility Solid Waste Activities Group (USWAG): a 1979 Envirosphere, Inc., study and a 1982 Dames and Moore study. To supplement these two major studies, in 1987 EPA conducted a literature review of all readily-available sources, which revealed only two additional case studies on proven damages occurring in 1980 and 1981. The Agency has not identified any proven damage cases in the last seven years; however, no attempt was made to compile a complete census of current damage cases by conducting extensive field studies.

As with all damage cases, it is not always clear whether damages could occur under current management practices or whether they are attributable to practices no longer used. As described in Chapter Four, there has been an increased tendency in recent years for utilities to utilize mitigative technologies, including a shift to greater use of landfills rather than surface impoundments and an increased use of liners.

5.3.1 Envirosphere Case Study Analysis

The Utility Solid Waste Activities Group (USWAG) and the Edison Electric Institute (EEI) commissioned the Envirosphere Company in 1979 to investigate and document available information on the nature and extent of the impact of utility solid waste disposal on public health, welfare, and the environment.[27] To conduct this analysis, Envirosphere reviewed various reports, including EPA's damage incident files, environmental monitoring studies at utility disposal sites, and other research and studies as available; they contacted state regulatory agencies to determine what information was available in state files.

From its review of the available data, Envirosphere found few documented cases where utility solid waste disposal had potentially adverse environmental effects. They identified nine cases from EPA's damage incident files that appeared to show damage to the environment. Envirosphere reviewed data from environmental monitoring studies at the utility disposal sites and other available research, and noted that the information available on the potential impacts of utility waste disposal was inconclusive. Some data indicated "... that elevated levels of some chemical parameters have occurred at locations downgradient of some utility solid waste disposal sites." Envirosphere concluded, however, that it was not clear to what extent these impacts could be attributed to utility solid waste disposal practices.

Some of the specific cases from Envirosphere's sources are summarized below:

- Texas, 1977. A clay liner was improperly installed in a 14.3 acre disposal pond for metal cleaning solutions. The liner dried and cracked before wastes were introduced into the facility. After the pond was put in service, ground-water monitoring wells detected contaminant migration. Levels of selenium and chromium occasionally exceeded the PDWS for these elements, and several SDWS were exceeded. The pond was taken out of service, the liner was saturated with water, and the pond was put back into operation.

- Indiana, 1977. Envirosphere found that leaching from two large, unlined ash disposal ponds was contributing to ground-water contamination. Arsenic and lead were found in downgradient ground water at concentrations about two times the PDWS, while concentrations of selenium were about four times the PDWS.

- Pennsylvania, 1975. A private waste handler illegally disposed fly ash in a marsh located in a tidal wetland area. Visual inspections by the state indicated marsh contamination due to fly ash leachate. When ordered to stop the dumping and clean up the site, the handler declared bankruptcy, and the ash remained in the marsh. Detailed analysis of any potential impacts has not been conducted.

- Connecticut, 1971. A municipal landfill, which was located in a marsh, accepted many substances, including large quantities of fly ash. Surveys revealed numerous SDWS contaminants, some of which appeared to be related to the ash. The site, considered unsuitable for disposal of solid waste, was closed and turned into a state park.

- Virginia, 1967. A dike surrounding a fly ash settling lagoon collapsed, and 130 million gallons of caustic solution (pH 12.0) were released into the Clinch River.

> Large numbers of fish were killed over a distance extending 90 miles from the spill site. Surveys conducted 10 days after the spill showed dramatic reductions in bottom dwelling fish food organisms for 77 miles below the release site. Virtually all such organisms were eliminated for a distance of 3 to 4 miles. The waste was eventually diluted, dispersed, and neutralized by natural physical/chemical processes. Two years after the spill, however, the river had not fully recovered.

5.3.2 Dames & Moore Study of Environmental Impacts

Dames & Moore, in a study for USWAG, conducted a survey of existing data and literature to document instances in which danger to human health and the environment was found to have occurred because of the disposal of coal combustion wastes.[28] Dames & Moore established criteria by which to evaluate whether a given record of a contamination incident could be considered "documented" evidence proving danger to health or the environment: 1) the report must exist in the public record; 2) the case must involve high-volume (utility) wastes; 3) information must exist to permit determination of possible health or environmental risks; and 4) the possible risks may have been caused by leachate migration or runoff from utility disposal sites.

The danger to health and the environment was examined by accounting for the types, concentrations, and locations of constituents shown to be present that could have harmful effects. In addition, Dames & Moore considered both the potential for public access to utility waste constituents and any observed effects on the population or environment. The three major data sources providing information reviewed in this study were computer data bases used to search for publicly available references; Federal Government agencies such as

EPA, U.S. Geological Survey, and the Tennessee Valley Authority; and 12 state environmental, natural resource, health or geological agencies.

Using information from these sources, Dames & Moore identified seven cases that presented a potential danger to human health and the environment. Six of the seven cases involved potential impacts from ground water and one case involved surface water. Dames & Moore concluded that none of these cases represented a "documented" case of such danger. However, Dames & Moore eliminated several sites from the documented category because they believed sufficient data from the sites were unavailable or did not meet the selection criteria described above. Dames & Moore evaluated in detail the seven sites at which there existed a potential for adverse environmental and health effects. Their findings are summarized below.

- Chisman Creek Disposal Site, York County, Virginia. The Chisman Creek disposal area was an inactive site with four separate fly ash disposal pits on both sides of Chisman Creek. An electric utility hired a private contractor to transport and dispose of fly ash and bottom ash from petroleum coke (a residual product of the oil distillation process) and coal combustion. The site was active from the late 1950's to 1974. In 1980, nearby residential drinking water wells became green from contamination of vanadium and selenium and could no longer be used. The site is currently on the CERCLA (Superfund) National Priorities List. A minimum of 38 domestic wells and 7 monitoring wells near the four disposal sites were sampled over time. Two off-site domestic wells located 200 feet from the disposal area had elevated concentrations of vanadium, selenium, and sulfate. One of these two wells was sampled four times. Three of the four measurements exceeded the PDWS for selenium up to 2 times. Another domestic well contained 0.11 mg/l of vanadium. (EPA has not established concentration limits for vanadium.) At both wells, sulfate concentrations exceeded the SDWS. In addition, samples from six of the seven monitoring wells exhibited increased concentrations of sulfates. The highest concentrations of selenium and vanadium that were observed in monitoring well samples were 0.03 (3 times the PDWS) and 30 mg/l, respectively. The high concentrations of selenium and vanadium were noticed in monitoring wells that were drilled directly through the disposal pits.

The Virginia State Water Control Board (SWCB) conducted the initial study at this site. The SWCB concluded that the quality of ground water immediately beneath and down-gradient from the site had been affected. Moreover, the SWCB stated that the water in the two domestic wells had elevated concentrations of selenium and vanadium because of the disposal of the fly ash. Dames & Moore was critical of the conclusions reached by the SWCB because of what they termed "significant data gaps." Dames & Moore cited a lack of background water quality information and a general lack of information on the well installation, sample collection procedures, and other possible sources of contamination, such as the York County landfill which is adjacent to one of the ash disposal areas. The two contaminated off-site domestic wells identified by the SWCB, however, were over 2,000 feet from the county landfill but within a couple of hundred feet from the ash disposal areas. Additionally, monitoring wells located between the landfill and the affected domestic wells did not register the same elevated concentrations of selenium. Residents in the area no longer rely on ground water for their drinking water.

- Pierce Site, Wallingford, Connecticut. Coal fly ash had been deposited at the Pierce Site since 1953. In 1978, the United States Geological Survey (U.S.G.S.) collected ground-water quality data from three on-site wells - one upgradient and two downgradient. The U.S.G.S. took samples from the wells on three days over a period of two months. One sample from one downgradient well showed a concentration of chromium that exceeded the PDWS by a multiple of 1.6. Concentrations of cadmium, manganese, zinc, and sulfate were higher in the downgradient wells than in the upgradient well.

According to Dames & Moore, there were not enough data at this site to state conclusively whether or not the ground water had been adversely affected by the fly ash pit. To determine potential damage to ground water quality, Dames & Moore stated that EPA recommends a minimum of three downgradient wells and one upgradient well. In this case, there were only two downgradient wells. Three samples over a period of two months were not considered sufficient because naturally occurring temporal changes in the area were believed to render comparisons invalid.

The Pierce disposal site is situated on a deposit of thick, stratified sediments composed of particles that range in size from clay to coarse sand. The disposal site is located within a few hundred feet of the Quinnipiac River, and the ground water flows from the site to the river, which diluted contaminants in the ground water. Although there are residences within a few blocks of the power plant, they do not use local ground water for drinking supplies.

- Michigan City Site, Michigan City, Indiana. The Michigan City site, situated on the shore of Lake Michigan, contained two fly ash disposal ponds. Ground-water flow at the site was towards Lake Michigan, facilitated by the porous sand that underlies the site. Twenty-one monitoring wells were installed at this site. Two of these were placed upgradient from the site outside the site boundaries; the remaining 19 wells were established within the boundaries of the facility and downgradient from the disposal areas.

Monitoring of the wells (which took place periodically over a one-year period) indicated that trace metals migrated from the disposal sites and that certain constituents had elevated ground-water concentrations. Arsenic and lead were observed in concentrations that exceeded their PDWS. Seven samples collected from three downgradient monitoring wells had arsenic concentrations that exceeded the standard -- up to 100 times the PDWS. All of the samples taken from the upgradient off-site monitoring wells contained arsenic at concentrations below the PDWS. Five of the downgradient monitoring wells contained lead concentrations which exceeded the PDWS, with the highest exceedance 7 times the PDWS. Three samples from the two upgradient monitoring wells also had lead concentrations in excess of the standard, with the highest exceedance 3 times the PDWS.

Dames & Moore concluded that effects on ground water appeared to be limited to areas within the facility boundaries because of attenuation mechanisms operative at the site -- absorption, dilution, precipitation, and a steel slurry wall installed between the disposal site and Lake Michigan. However, no downgradient monitoring wells were situated off-site. Based on the locations of the waste disposal sites and the monitoring wells, it appears that the ash ponds are responsible for arsenic concentration above the PDWS in the ground water within the site boundaries. Because high lead concentrations were observed in some of the upgradient background wells, it is impossible to state with certainty that the high lead concentrations in the ground water are attributable to the disposal sites. Dames and Moore noted that nearby residents do not use the ground water for their water supply.

- Bailly Site, Dune Acres, Indiana. The Bailly site is located near the Indiana National Lakeshore on Lake Michigan in a highly industrialized area. Fly ash at this site has been slurried to interim settling ponds, which are periodically drained. The drained ash is then disposed in an on-site pit. Two aquifer units, designated Unit 1 and Unit 3, underlie the site. Unit 1 contains fine-to-medium sand and some gravel, while Unit 3 is composed of sand with overlying layers of varying amounts of sand, clay and gravel.

  Ground-water samples from Unit 1 were collected from an upgradient well and from several wells downgradient from the ash settling ponds. Samples from Unit 3 were collected upgradient and from one well downgradient from the ash ponds. These wells were sampled at five-week intervals between September 1976 and May 1978.

  In samples from Unit 1, arsenic, cadmium, fluoride, and lead occasionally exceeded the PDWS. Upgradient concentrations of arsenic never exceeded the PDWS, whereas the maximum downgradient concentration for arsenic was 4.6 times the PDWS. Downgradient on-site concentrations of cadmium exceeded the PDWS at one well by 25 times, while the maximum upgradient concentration of cadmium exceeded the PDWS by 22 times. One downgradient well measurement indicated lead concentrations that exceeded PDWS by 1.26 times.

  All of the above-mentioned exceedances were observed in Unit 1. None of the samples from Unit 3 contained constituents at concentrations that exceeded the PDWS.

  Aluminum, boron, iron, manganese, molybdenum, nickel, strontium, and zinc all increased in concentration downgradient from the disposal areas, though not in levels exceeding the SDWS.

  Leachate from the ash disposal ponds is the most probable contributor to the increased concentrations of arsenic and lead observed in the aquifer samples taken from the on-site wells. Cadmium was the only constituent whose downgradient off-site concentration was observed to exceed the PDWS. However, because elevated cadmium concentrations were also found in samples taken from the background well, the elevated concentrations of cadmium may not have been caused by the leachate from the coal ash. Dames and Moore noted that ground water at this site flows away from the nearest residential area.

- Zullinger Quarry Fly Ash Disposal Site, Franklin County, Pennsylvania. The Zullinger quarry was situated in a limestone formation in south-central Pennsylvania. The quarry was excavated to 40 feet below the water table. Fly ash was deposited in the quarry from 1973 to 1980 with no attempt to dewater the quarry prior to placement of the fly ash.

The site operator, consultants, and the Pennsylvania Department of Environmental Resources (DER) have been independently involved in water quality investigations at the site. Initially, six monitoring wells were established onsite. Later, several existing off-site domestic wells were added to the sampling program. Two of the monitoring wells were installed upgradient to provide background constituent concentrations. The other monitoring wells, and the domestic wells in the sampling program, were downgradient from the fly ash deposited in the quarry.

Lead was found to exceed its PDWS by up to eight times in eight out of over 100 samples. Six of these eight exceedances occurred in two on-site monitoring wells, while the seventh (2.6 times PDWS) was found in an off-site domestic well. Another exceedance (1.5 times PDWS) was found in the background well.

Several constituents for which there are secondary drinking water standards were found in elevated concentrations downgradient from the ash disposal site. Sulfate concentrations increased dramatically during the first few years of quarry filling, then began to sharply decline in 1976 when the fly ash had filled the quarry. From 1976 until deactivation of the disposal site in 1980, the fly ash was deposited above the water table. Zinc and iron were also found in elevated concentrations. Elevated levels of sulfate, zinc, and iron are probably attributable to leachate from the fly ash, as are the lead levels in excess of the PDWS. Most of the trace metals appear to be attenuated onsite by the limestone formation.

- Conesville Site, Conesville, Ohio. Various types of coal combustion waste had been deposited at the Conesville site in central Ohio. The monitoring program at the Conesville site was established to determine the ability of an FGD sludge fixation process (Poz-O-Tec, a solid material produced by mixing FGD sludge with fly ash and lime) to stabilize and thus immobilize potential contaminants. The stabilized FGD sludge has been deposited next to a fly ash pond. Permeable sand and gravel underlie the Muskingum River flood plain on which the Conesville site is located.

  A total of 34 monitoring wells were installed at the Conesville site. Two of the wells were situated upgradient from the disposal area to provide the necessary background water quality data. Two sets of water quality data were taken, the first between February 27 and April 12, 1979, and the second between December 4, 1979, and July 10, 1980.

Some samples from the first set of data contained constituents at concentrations that exceeded the PDWS. Lead concentrations exceeded the PDWS in two on-site wells by up to 3 times and three off-site wells by up to 2 times. The concentration of mercury found in one sample from an on-site well exceeded the PDWS by 1.4 times; however, this exceedance could not be attributed to the fly ash. One of the fourteen background measurements had the highest observed concentration of selenium, 6 times the PDWS. Thus, selenium appears to be leaching from indigenous sediments rather than from the FGD waste and fly ash deposited at the site. The first set of data also showed the SDWS constituents of calcium, magnesium, total dissolved solids, sulfate, and iron, had increased in those wells located on the site property and just across the property boundaries.

Measurements taken between December 1979 and July 1980 showed increases in calcium, magnesium, total dissolved solids, and sulfate relative to those measurements taken in the first data collection period. Concentrations in excess of the PDWS were found for selenium (several wells), arsenic (one sample), cadmium (four samples), and chromium (five samples). Two of the chromium exceedances were found in on-site wells, while three occurred in off-site wells, with concentrations ranging up to 16 times the PDWS on-site and 2 times the PDWS off-site. Background wells also had elevated levels of selenium. The single arsenic exceedance (2.4 times the PDWS) and all of the cadmium exceedances (up to 12 times the PDWS) were detected in on-site wells. In contrast to the first round of sampling, lead was not detected in concentrations greater than the PDWS. The only constituents that appear to be migrating offsite are lead and chromium. Based on the data collected, it appears there may be a temporal variation in the water quality at this site. Dames and Moore noted that the town of Conesville is downgradient from the site but on the other side of the river, which would tend to mitigate potential adverse impacts.

- <u>Hunts Brook Watershed, Montville-Waterford, Connecticut</u>
  The electric utility hired a private contractor to transport and dispose of fly ash in three separate sites (Chesterfield-Oakdale, Moxley Hill, and Linda Sites) along three different tributaries to Hunts Brook. Disposal of fly ash in this area began in the mid 1960's and ended in 1969. The surface-water quality studies that took place in this area focused on pH, iron,

sulfate, and total dissolved solids (TDS). No analyses were performed for any of the PDWS constituents. Upstream surface water samples were compared to downstream samples to determine if the surface water quality had been degraded at any of the sites.

At the Chesterfield-Oakdale site, concentrations of iron in the surface water increased from less than the SDWS to more than 100 times the SDWS between the upstream and downstream sampling points. Sulfate concentrations increased by over an order of magnitude, from 20 to 299 mg/l, (at 299 mg/l, still only 1.2 times the SDWS) between the upstream and downstream sampling positions, while TDS increased from less than the SDWS to 44 times the SDWS. At another sampling point approximately 1.2 miles downstream from the site, the measured parameters had all returned to levels close to the upstream values.

At the Moxley Hill Site, the pH and iron concentrations remained relatively constant between the upstream and downstream sampling points; median sulfate values increased, although not to levels exceeding the SDWS. The elevated concentrations of sulfate and TDS had been significantly attenuated at another point three-quarters of a mile downstream.

At the Linda Site, no upstream data were collected. It is therefore impossible to quantify the potential effects of fly ash deposition on the water quality.

5.3.3 Other Case Studies of the Environmental Impact of Coal Combustion By-Product Waste Disposal

This section presents a review of two independent case studies of ground-water contamination at utility disposal sites.

Cedarsauk Site, Southeastern Wisconsin

The Cedarsauk site is a fly ash landfill in southeastern Wisconsin. At the time of this study,[29] fly ash had been deposited at the site into an abandoned sand and gravel pit over a period of eight years. Part of the pit is in direct contact with an aquifer composed mainly of sand and gravel with some clay. This upper aquifer is approximately 15 to 20 meters thick with a permeability of 10^{-3}

to 10^{-2} cm/sec. Soluble carbon aqueous material comprises about 35 percent of the aquifer. The upper sandy aquifer overlies another aquifer consisting of fractured dolomite-bedrock.

A water quality study of the area was undertaken in 1975. This study eventually included 35 monitoring wells and seven surface-water sampling sites. Twenty of the wells were placed upgradient of the site to provide background water quality information, while the remaining wells were positioned downgradient. Sampling was performed on a monthly basis. Most of the ground-water flow beneath the site surfaced in a marsh directly east of the ash disposal area.

The monitoring results showed that downgradient ground water had SDWS exceedances. Background levels of total dissolved solids (TDS) were below 500 mg/l, while the levels in the ground water downgradient from the disposal site exceeded 800 mg/l, or 1.6 times the SDWS. After eight years of disposal, the contaminant plume appeared to stabilize approximately 200 meters downgradient from the ash disposal site. The stabilization of the constituent plume appeared to be due to dilution and the ability of the materials in the aquifer to attenuate contaminants. Only iron, manganese, and zinc were found in detectable quantities in the downgradient off-site wells.

The maximum detected iron concentration was more than 33 times the SDWS, while the maximum manganese concentration reached 30 times the SDWS. Neither iron nor zinc could be detected 200 meters downgradient from the disposal site. Another contributor to ground-water contamination at this site was sulfate. Background concentrations of sulfate varied between 20 and 30 mg/l (well below the SDWS), while the concentrations of sulfate in the contaminant plume achieved levels approximately 3.4 times the SDWS. Other trace metals for which analyses were performed, such as copper, molybdenum, nickel, lead, and titanium, were not detected.

As the leachate contacted the sediments in the aquifer, it was neutralized from an initial pH value of 4.5 to around neutral pH levels (i.e., about 7.0). This change in pH probably caused the precipitation of many of the trace metals and other constituents in the leachate. In addition, adsorption reactions between the clay in the sediments and the constituents probably attenuated the leachate concentrations of many of the potential contaminants observed in the leachate.

Center Mine, Center, North Dakota

Fly ash at this site had been deposited in a mine pit and between mine ash piles. A study was conducted to determine the potential effects of FGD and fly ash disposal on ground water quality at the surface mining site.[30] This investigation used field monitoring and laboratory column leaching experiments in conjunction with geochemical computations. By collecting both field and laboratory data, the investigators hoped to test the applicability of laboratory column experiments to field situations. Roughly 150 wells were placed both in the vicinity of the waste disposal sites and in unaffected areas.

Ground-water concentrations were generally within drinking water standards in the background wells. However, selected constituents were higher than the drinking water standards. For instance, sulfate concentrations tended to exceed the SDWS by a factor of 2 to 4. The maximum iron concentration was 4.3 times the SDWS. Manganese concentrations were all above the SDWS, varying from 0.06 to 2.75 mg/l, or 1.2 to 55 times the SDWS.

Samples collected from wells located adjacent to the FGD waste site indicated that none of the PDWS constituents exceeded the standards. For the SDWS constituents, molybdenum concentrations fluctuated between 0.070 and 4.850 mg/l, and sulfate concentrations reached a high of 9,521 mg/l, or 38 times the SDWS. (EPA has not established maximum concentration levels for molybdenum.)

Ground water in areas that appear to be affected by leachate from the fly ash disposal sites had sulfate concentrations ranging from 21.7 to 211 times the SDWS. Higher values were obtained immediately below recent deposits of fly ash, while lower values were observed at older sites or at greater distances from the disposal area. Arsenic and selenium concentrations in the ground water were as high as 0.613 mg/l (12 times the PDWS) and 0.8 mg/l (80 times the PDWS), respectively. The highest arsenic and selenium concentrations were associated with higher pH values. Ground-water pH values for samples in the area of the fly ash ranged from 6.95 to 12.1. (The Secondary Drinking Water Standard for pH is 6.5 to 8.5). Iron and manganese concentrations were also high in samples taken from around the fly ash disposal site. The maximum concentration of iron was 8.6 times the SDWS; the maximum concentration of manganese was 130 times the SDWS.

Leachates from the fly ash of western coals are often characterized by a high pH that tends to cause many potentially harmful constituents to be released. The pH-dependent solubility of many trace elements, as apparently observed at this site, demonstrates the importance of neutral pH values that are conducive to contaminant attenuation.

5.3.4 Summary

The studies reviewed in this section indicate that constituents from coal-combustion waste disposal sites have been detected in both on-site and off-site ground and surface water. However, those constituents that did exceed the drinking water standards seldom exceeded these standards by more than ten times. Moreover, the total number of exceedances is quite small compared to the total number of monitoring wells and samples gathered. The contaminant exceedances that do occur appear to be correlated to some extent with acidic or alkaline pH levels. At fly ash disposal sites, pH values between 2 and 12 have been measured. High and low pH values can contribute to metal solubility in ground water.

There are two documented cases of coal combustion waste disposal sites causing significant harm to the environment. Drinking water wells around the Chisman Creek fly ash disposal site in Virginia (which was closed in 1974) were contaminated with high concentrations of vanadium and selenium. Concentrations of these elements at this site were also due to petroleum coke waste (a product of oil combustion, not coal combustion). The site has been placed on the CERCLA National Priority List. In 1967, a dike failed at a utility waste disposal site on the banks of the Clinch River in Virginia, causing waste to spill into the river. This accident caused substantial damage to the biotic life in the river.

5.4. FACTORS AFFECTING EXPOSURE AND RISK AT COAL COMBUSTION WASTE SITES

The previous sections analyzed the constituents of coal combustion waste leachates and the quality of the ground water and surface water surrounding disposal sites. However, this is only part of determining the potential dangers that the wastes pose to human health and the environment. Exposure potential, the degree to which populations could be expected to be exposed to potentially harmful constituents, must also be analyzed. Exposure potential is determined by a variety of factors. Hydrogeologic characteristics of a site will affect the migration potential of waste constituents. Proximity of sites to drinking water sources and to surface-water bodies will determine potential for exposure to populations using the water sources.

In order to address this issue of exposure, EPA collected a wide variety of data on a random sample of 100 coal-fired utility plants around the country. The sample was taken from the Utility Data Institute Power Statistics Database, which contains information on every coal-fired electric utility plant in the country. Most plants dispose of their waste on-site, and in these cases information was collected on the plant location given by the data base. If the plant disposed off-site, data were collected on that off-site location. EPA assumed that off-site disposal took place at the nearest municipal landfill, unless additional information indicated otherwise. Characteristics such as depth to ground water, hydraulic conductivity, distance to surface water, location of private and public drinking water systems, type of surrounding natural ecosystems, and location of human population were obtained from a wide variety of sources. This simple aggregation of the individual factors affecting exposure at coal combustion waste sites provides a qualitative perspective on the potential risk that coal combustion waste sites pose, and is presented in Sections 5.4.1-5.4.3. Appendix F displays the data for each coal combustion waste site in the random sample.

5.4.1 Environmental Characteristics of Coal Combustion Waste Sites

Environmental characteristics of coal combustion utility waste sites will have a significant effect on the potential for the waste constituents to travel and reach receptor populations. Key environmental characteristics are:

- Distance to surface water - The distance between a coal combustion waste disposal site and the nearest surface water body. Proximity to surface water would decrease the possible health effects of ground-water contamination due to the fact that there would be fewer opportunities for drinking water intakes before the ground water reached the surface water body; once the plume reached the surface water, contamination would be diluted. However, proximity to surface water would possibly increase danger to aquatic life because less dilution of the contaminant plume would occur before the plume reached the surface water body.

- Flow of surface water - A high surface water flow will increase the dilution rate of coal combustion constituents that may enter the surface water, thereby reducing concentrations in the surface water.

- Depth to ground water - The distance from ground level to the water table. A larger depth to ground water will increase the time it takes for waste leachates to reach the aquifer; it also allows more dispersion of the leachate before it reaches the aquifer so that once the leachate reached the aquifer, concentrations of metals would be decreased.

- Hydraulic conductivity - This factor is an indication of the rate at which water travels through the aquifer. A high hydraulic conductivity indicates that constituents will travel quickly through the ground water and possibly more readily reach drinking water wells, although high conductivity also indicates a more rapid dilution of constituent concentration.

- Net recharge - This factor is a measure of net precipitation of a site after evapotranspiration and estimated runoff is subtracted. Recharge is calculated in order to determine the amount of rainfall annually absorbed by the soil. A high net recharge indicates a short period of time for contaminants to travel through the ground to the aquifer, but will also indicate a higher potential for dilution.

- Ground-water hardness - This factor is a measure of the parts per million (ppm) of calcium carbonate ($CaCO3$) in the aquifer. Ground water with over 240 ppm of $CaCO3$ is typically treated when used as a public drinking water supply. This treatment of the hard ground water has an indirect mitigative effect on exposure because treatment of the ground water will tend to remove contamination from other sources.

To conduct this exposure analysis, environmental data on the 100 randomly selected coal combustion waste sites were gathered using a number of sources. These data were then aggregated in order to present an overview of the environmental characteristics that contribute to exposure. The data collected on the sample of coal combustion waste sites were compared to information presented in a study by Envirosphere for the Electric Power Research Institute.[31] The Envirosphere report gave detailed information on the hydrogeologic settings of 450 operating utility plants. The information provided by the exposure analysis on the sample of 100 plants corresponded fairly closely with the settings described in the Envirosphere report.

The following sections summarize the data that were collected and the relationship of the various characteristics to potential exposure.

5.4.1.1 Distance to Surface Water and Surface-Water Flow

The proximity of a waste site to surface water affects exposure potential in several ways. If the site is very near a surface-water body, there is less opportunity for humans to use contaminated ground water as a source of drinking water. However, sites that are close to surface water can more easily contaminate the surface-water body, although waste constituents will be more quickly diluted if the flow of the surface water is high.

Distance to the nearest surface-water body, e.g., creek, river, lake, or swamp, was determined from measurements obtained using United States Geologic Survey (U.S.G.S.) maps. The sample of coal combustion waste sites was located on 7-1/2 or 15 minute maps, and the distance between the site and nearest surface water body was calculated.

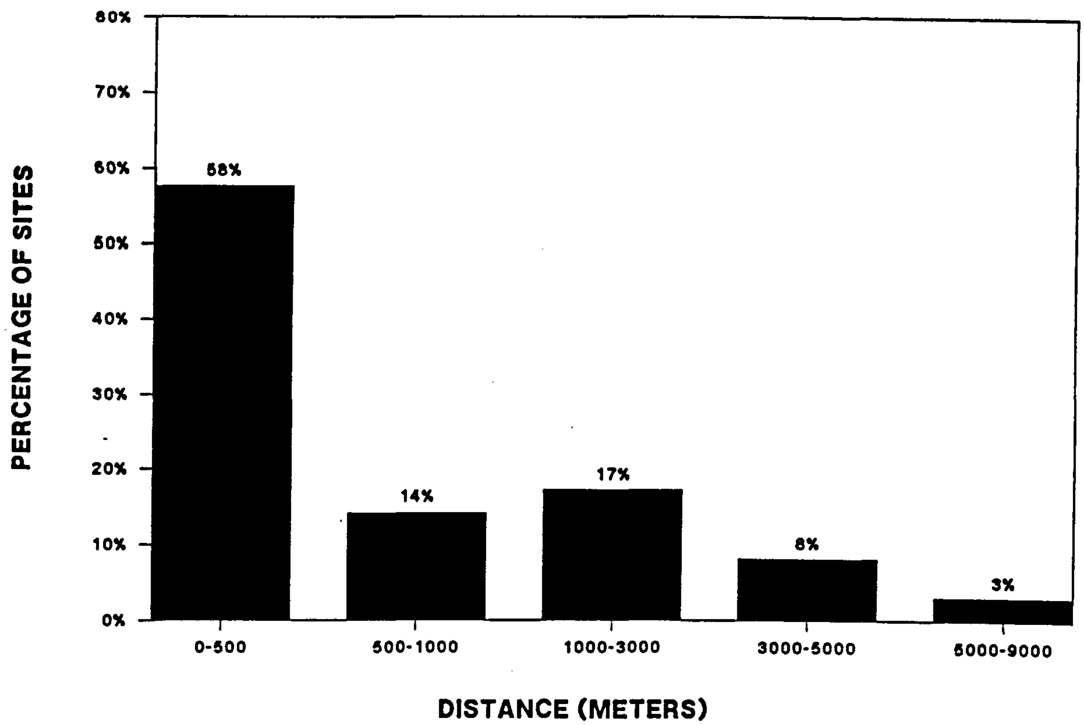
When the boundaries of the plant or waste site were marked on the maps, the reference point was the downgradient boundary of the site. If the boundaries were not marked, the latitude and longitude points for the sites provided by the Utility Data Institute Power Statistics Database were used.

The average distance from the sample of coal-burning waste sites to surface-water body is 1279 meters. Distances range from 10 to 18,000 meters. Over 50 percent of the disposal sites are within 500 meters of surface water; more than 70 percent are within 1,000 meters of surface water. Exhibit 5-17 provides the number and percentage of sites within specified distances of surface water.

Since most sites are located somewhat near surface-water bodies, the potential for human exposure to contaminated ground water seems to be low. The proximity of the sites to surface water could, however, pose a threat to aquatic life and to humans using the surface water if contaminants are entering

EXHIBIT 5-17

DISTANCE OF COAL COMBUSTION WASTE SITES TO SURFACE WATER



SOURCE: ICF Inc, based on USGS data

the surface water. The concentration in surface water will be less, however, if the surface-water body close to the site has a high flow.

Flow data on surface-water bodies near the sample of 100 sites were obtained from U.S.G.S. data. Flow is expressed in terms of cubic feet per second (cfs), and given for minimum and maximum average flow for one-month periods. In order to obtain a conservative estimate of exposure (i.e., one that does not understate exposure) this report used estimates for the month with the minimum monthly flow. The results are presented in Exhibit 5-18.

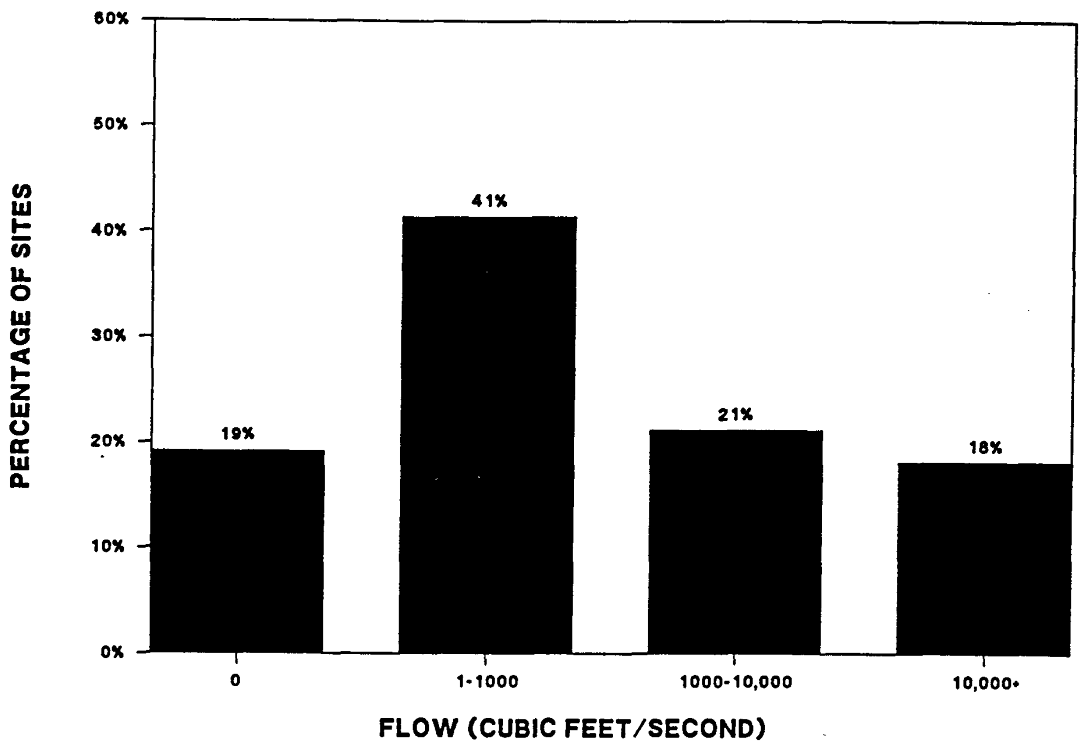
Exhibit 5-18 shows that 19 percent of the sites have a flow of zero. A zero flow generally indicates that the body of water is a lake, swamp, or marsh that does not have any continual flow of water, although this category could include a seasonal stream. For surface-water bodies with zero flow, dilution of potential contamination would occur because of the volume of water in the surface-water body, but there would not be any additional dilution as water flowed away from the source of contamination. Forty-one percent of the surface-water bodies have a flow of 1-1000 cubic feet per second, 21 percent have a flow of 1,000-10,000 cfs, and 18 percent have a flow of over 10,000 cfs.

5.4.1.2 Hydrogeologic Measurements

The hydrogeologic measurements of depth to ground water, hydraulic conductivity, and net recharge were determined through the use of information provided by the DRASTIC system. The DRASTIC system, developed by the National Well Water Association, categorizes aquifers on the basis of geographic region and subregion. Each site was located on a 7 1/2 or 15 minute U.S.G.S. map that

EXHIBIT 5-18

FLOW OF NEAREST SURFACE-WATER BODY



SOURCE: ICF Inc, based on USGS data

was then compared with a map on which the 11 major DRASTIC regions had been outlined. The topography and geology of the sites, which were determined from looking at the U.S.G.S. maps, were assessed in order to further classify thesites into DRASTIC subregions. Subregions are defined by hydrogeologic characteristics and vary in size from a few acres to hundreds of square miles. Measurements for depth to ground water, hydraulic conductivity, and net recharge of the sites were taken largely from A Standardized System for Evaluating Ground-water Pollution Potential Using Hydrogeologic Settings, by the National Well Water Association, which presents a range of values for each of these hydrogeologic properties for each subregion.[32] The ranges were compared with characteristics that could be observed by studying U.S.G.S. maps, and, when necessary, they were modified accordingly.

Depth to Ground Water

A small depth to ground water indicates a higher potential for waste constituents to reach the ground water at harmful concentrations than if the distance to ground water were greater, thereby increasing the chance of ground-water contamination. Depth to ground water was generally based on DRASTIC region and subregion, but was modified when the topography or site characteristics indicated a depth different from that provided by the DRASTIC system. For example, if the DRASTIC subregion indicated that there was a high depth to ground water range, but a particular site was located very near a surface-water body, the Agency used a smaller depth to ground water than the DRASTIC range indicated.

Exhibit 5-19 provides the number and percentage of sites within each range of depth to ground water. Depth to ground water is calculated in feet and based on 10 ranges. In over 80 percent of the sites depth to ground water is less than 30 feet, indicating a reasonably high potential that leachate from the disposal site would reach the ground water.

Hydraulic Conductivity

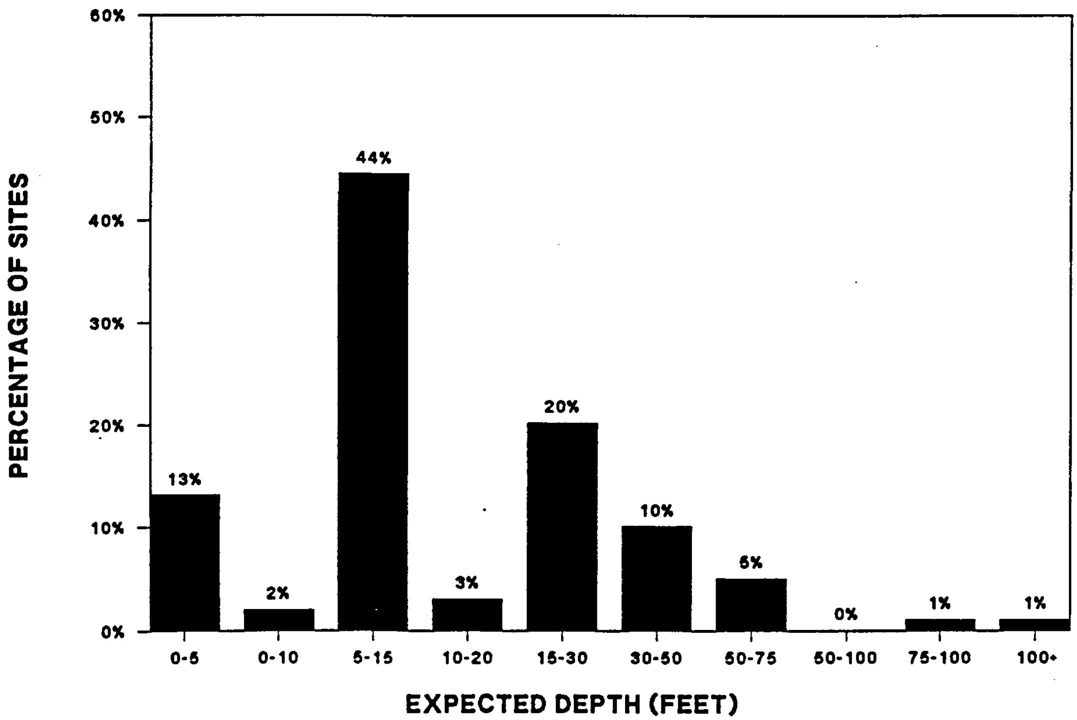
Hydraulic conductivity is an indication of the ease with which a constituent may be transported through the ground water. Conductivity is also based on the site's DRASTIC region and subregion, and is measured in gallons per day per square foot and grouped into six ranges.

Hydraulic conductivity is one of the factors used to calculate ground-water velocity, or volumetric flow of the water table. Velocity has a direct bearing on the degree to which leachate constituents are diluted once they reach the ground water and travel to a point of exposure (i.e., human drinking water source). High ground-water conductivity signifies high velocity and therefore a high dilution potential.

Exhibit 5-20 provides the number and percentage of sites falling into each hydraulic conductivity range. Thirty-three percent of the sites show a hydraulic conductivity of 700-1,000 gallons per day per square foot; 27 percent have a conductivity of 1,000-2,000 gallons per day per square foot. There is a wide spread of conductivity values -- indicating hydrogeologic diversity among sites.

EXHIBIT 5-19

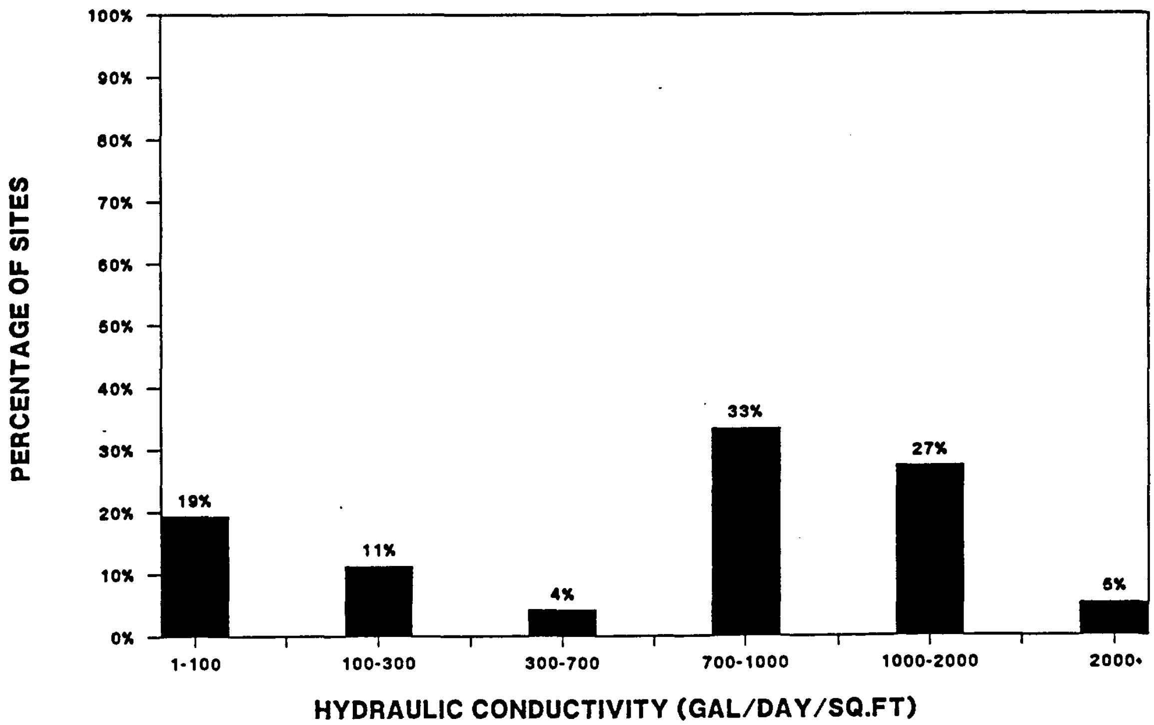
DEPTH TO GROUND WATER
AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on DRASTIC

EXHIBIT 5-20

HYDRAULIC CONDUCTIVITY
AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on DRASTIC data

While ground-water velocity gives an indication of how fast contamination may travel in the ground water, contaminants do not move at the same velocity as the ground water. This is because of basic interactions between contaminants and soil that retard the movement of the contaminants. There are three different mechanisms that affect the retardation of contaminant movement -- exchange on soil particle sites (ion exchange), adsorption onto soil particle surfaces, and precipitation. The exchange and adsorption mechanisms will retard the movement of contaminants but will not eliminate the movement of all contaminants due to limited soil attenuation capacity.

As with the diversity among sites in terms of hydraulic conductivity and ground-water velocity, the various attenuation mechanisms differ among sites. To determine the attenuation potential at a site requires detailed data inputs on water chemistry on a site-specific basis.

Net Recharge

Net recharge indicates how much water is annually absorbed into the ground. It is measured by subtracting evapotranspiration (the amount of rainfall that evaporates and transpires from plant surfaces) and estimated runoff from total precipitation at a site. It affects exposure potential in a number of ways. Low recharge will result in smaller volumes of more concentrated leachate, but if the aquifer is deep and/or has a high velocity, it will quickly dilute the leachate. High recharge produces more leachate, but may also indicate that the area has higher ground-water flow.

Exhibit 5-21 shows the number and percentage of sites that fall into each range. Recharge is measured in inches and is grouped into five ranges. Although a wide variety of net recharge ranges is represented by the sample, the recharge of sites generally falls into the higher ranges of 4-7 inches, 7-10 inches, and over 10 inches. For example, more than 80 percent of the sites have a net recharge of over 4 inches and over 50 percent have a recharge of over 7 inches. This implies that leachate constituents will be more quickly carried to the water table but the higher recharge rate will also result in greater dilution of the leachate.

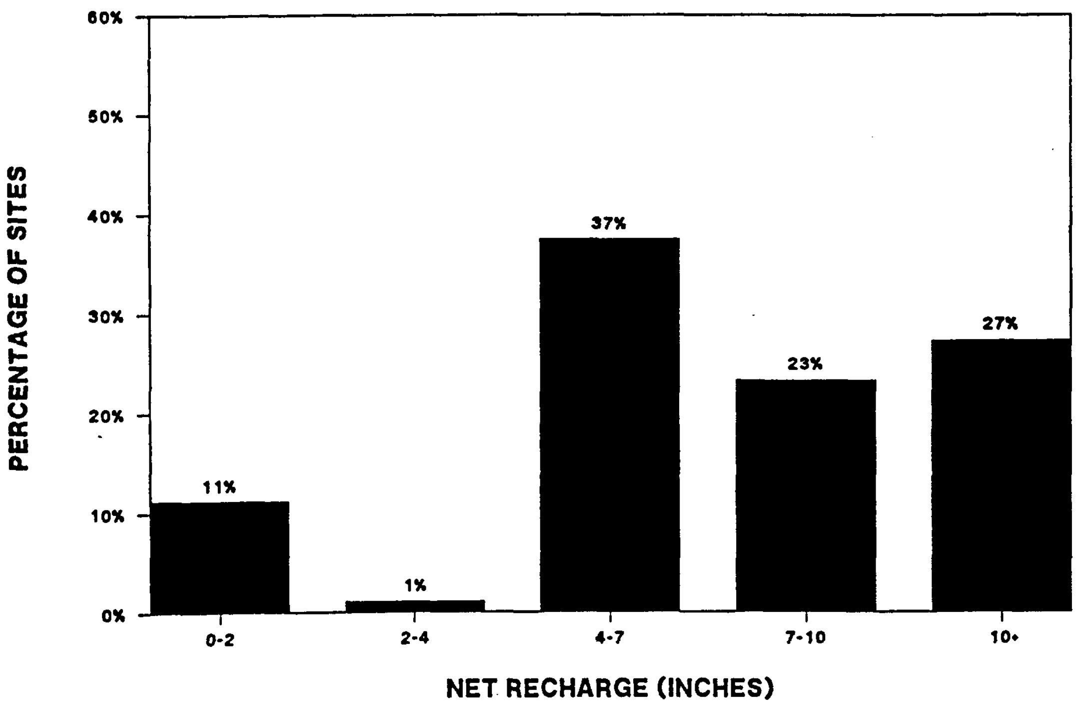
Ground-water Hardness

The hardness of the ground water near coal combustion waste sites will have an effect on potential exposure through drinking water since excessive hardness is typically treated in a public drinking water system. Treatment would lessen the exposure potential to humans from contaminants in the ground water from other sources (such as coal combustion wastes). Measurements for ground-water hardness were obtained by locating the sites on maps provided in Ground-water Contamination in the United States (Pye, Patrick, and Quarles).[33]

As shown in Exhibit 5-22, ground-water hardness is measured in parts per million (ppm) of calcium carbonate ($CaCO3$) and grouped into five ranges. Ground water with a hardness of over 240 ppm of calcium carbonate is typically treated if used in a public drinking water system. In this sample, 45 percent of the sites show ground-water hardness in this range. Ground water with a hardness of 180-240 ppm of calcium carbonate may also be treated, although

EXHIBIT 5-21

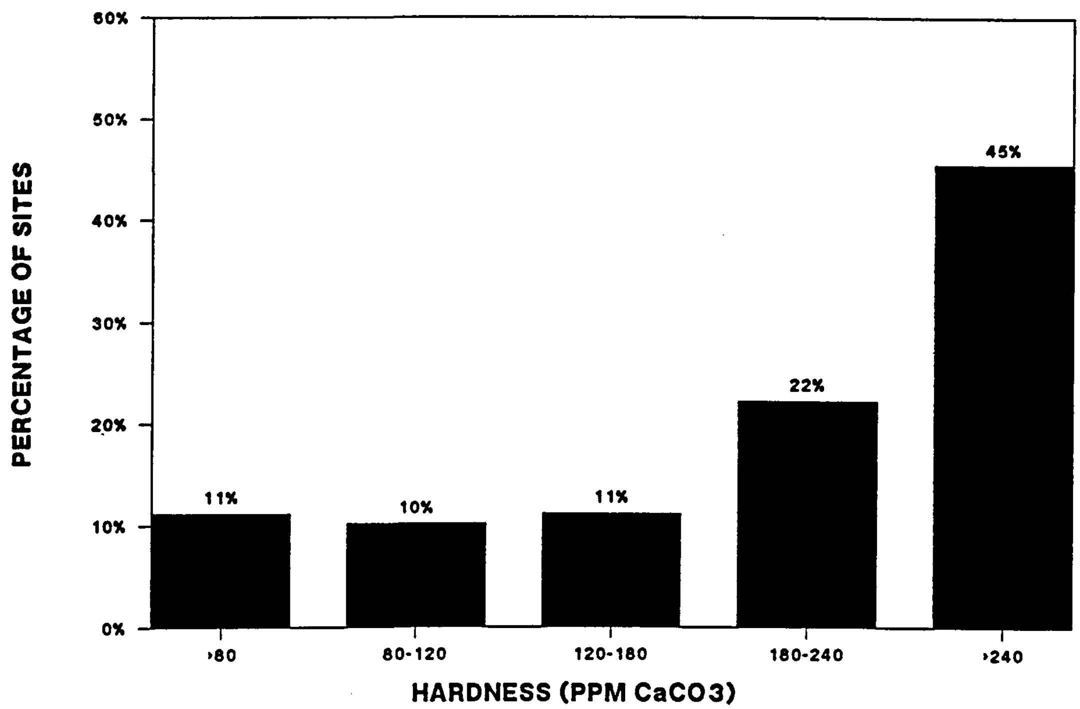
NET RECHARGE
AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on DRASTIC

EXHIBIT 5-22

GROUND-WATER HARDNESS
AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on Pye, et al, Groundwater Contamination in U.S.

treatment is much less likely. An additional 22 percent fall in the 180-240 ppm range.

The high levels of calcium carbonate found in the ground water near coal combustion waste disposal sites suggest that if a drinking water supply is in the vicinity, the water would often require treatment before being used. Therefore, contamination that might exist in the drinking water from other sources would be mitigated due to the treatment process since trace constituents tend to be removed during the treatment process.

5.4.2 Population Characteristics of Coal Combustion Waste Sites

Environmental characteristics, such as distance and flow of surface water and hydrogeologic measurements, are only one part of the analysis of exposure potential. Opportunities for human exposure to coal combustion waste constituents depend in part on the proximity of coal combustion waste disposal sites to human populations and to human drinking water supplies. Census data (1980) provide information about the number of people living within specified distances from the coal combustion waste sites. This information is obtained through the CENBAT program, part of the Graphic Exposure Modeling System developed by EPA's Office of Solid Waste. The Federal Reporting Data System (FRDS) data base, developed by EPA's Office of Drinking Water, provides estimates of the number of public water supply systems and the size of the populations using them.

5.4.2.1 Proximity of Sites to Human Populations

CENBAT provides information on the number of people living within specified distances around designated locations. The sites were defined by latitude and longitude coordinates. Populations were analyzed for areas within 1-, 2-, 3-, 4-, and 5-kilometer radii of the waste disposal sites.

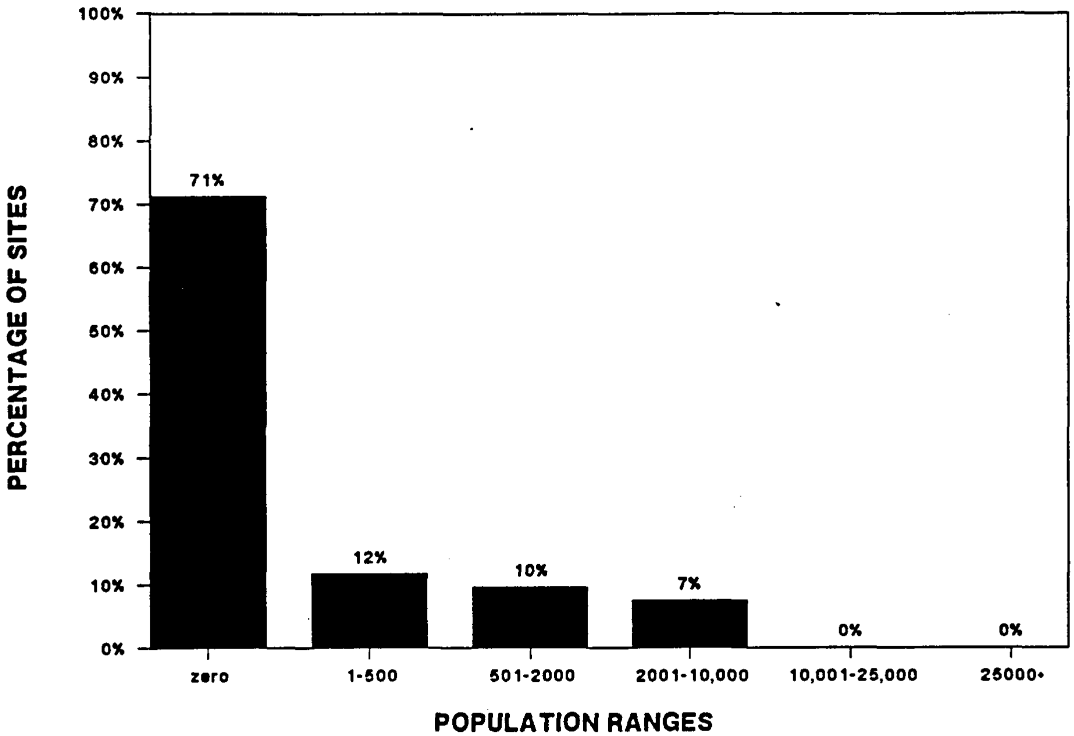
Exhibit 5-23 shows the distribution of population within one kilometer of the waste disposal sites. The CENBAT results show that most sites, 71 percent, do not have any population within a one-kilometer radius. Overall, the population range within a one-kilometer radius is 0 - 3708 people, with an average of 359 people.

Exhibit 5-24 shows the population characteristics for the sample of coal combustion waste sites at a three-kilometer radius. When the search distance is increased to three kilometers, the percentage of sites that have no people within a three-kilometer radius decreases to 32 percent. Average population within three kilometers is 3,737, and the range is 0 - 35,633 people. There is a large degree of diversity of populations at this distance. For example, while 32 percent of the sites have zero population, the same percentage has populations over 2,000.

Exhibit 5-25 shows the distribution of populations within a five-kilometer radius. Only 10 percent of the sites do not have any population living within this distance. The average population is 12,128 people, with a range from 0 to 123,160. The diversity among coal combustion waste disposal sites is even more apparent at this distance. While 20 percent of the sites have populations

EXHIBIT 5-23

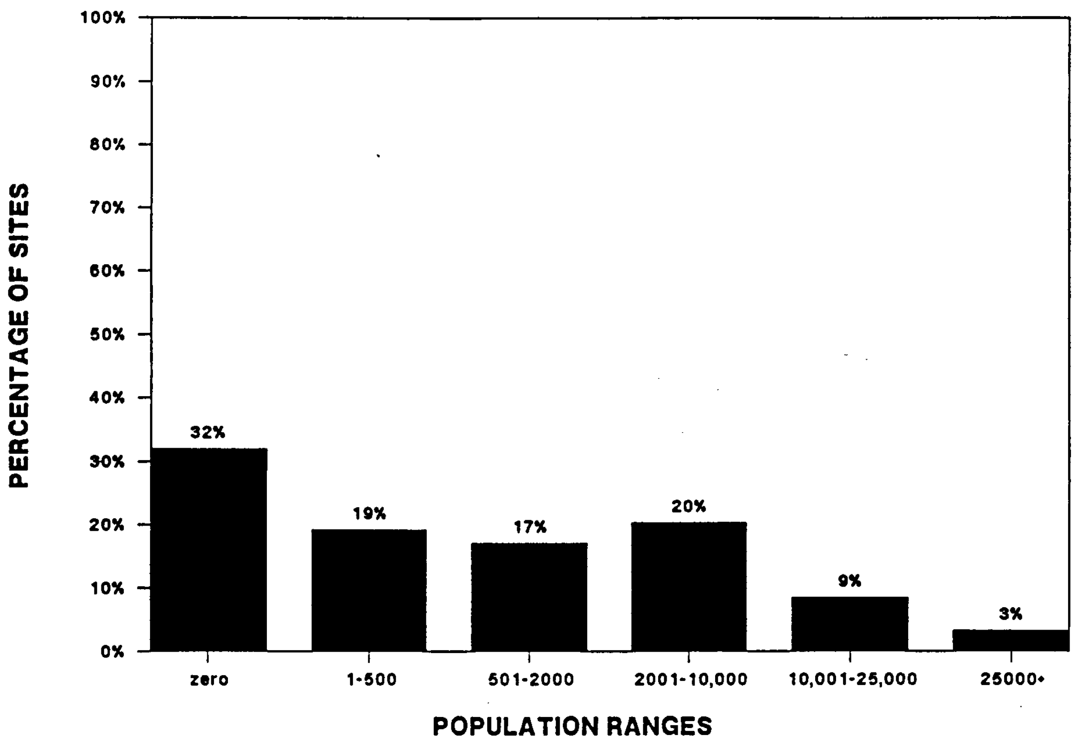
POPULATIONS WITHIN ONE KILOMETER OF WASTE SITES



SOURCE: ICF Inc, based on CENBAT data

EXHIBIT 5-24

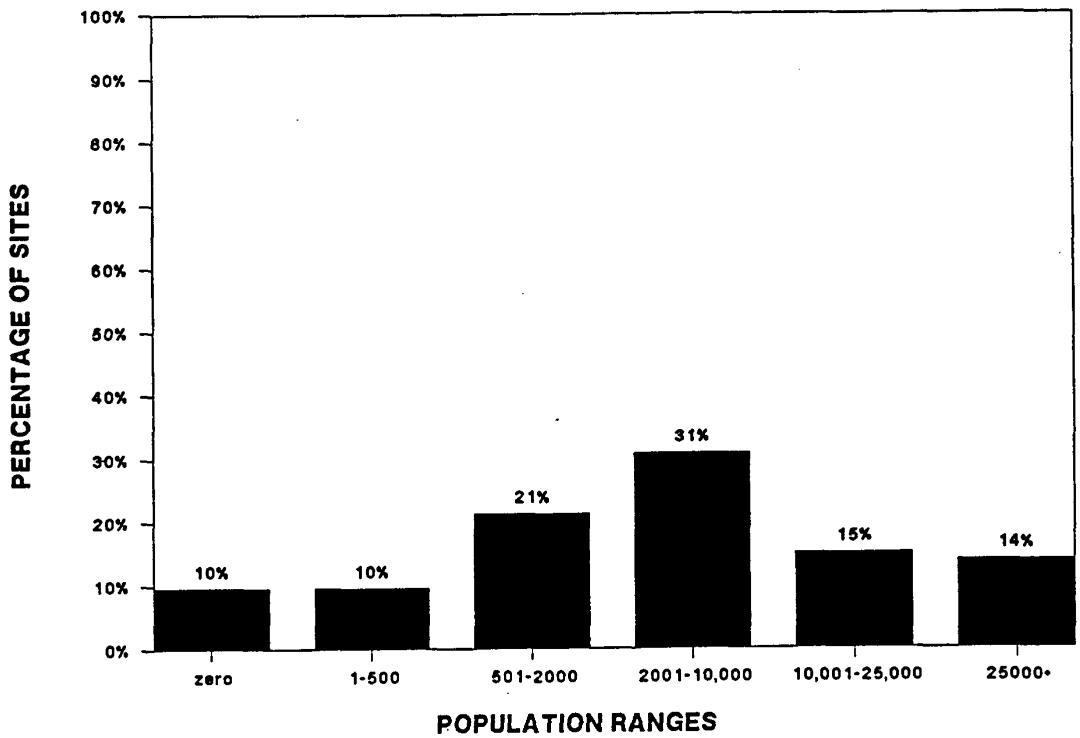
POPULATIONS WITHIN THREE KILOMETERS OF WASTE SITES



SOURCE: ICF Inc., based on CENBAT data

EXHIBIT 5-25

POPULATIONS WITHIN FIVE KILOMETERS OF WASTE SITES



SOURCE: ICF Inc., based on CENBAT

within a five-kilometer radius of fewer than 500 persons, 29 percent have populations over 10,000.

The CENBAT results indicate that density increases on average with distance from the disposal site. Many waste sites appear to be located on the outskirts of populated areas, with fairly low population immediately adjacent to the site, but with significant populations within a five-kilometer radius.

5.4.2.2 Proximity of Sites to Public Drinking Water Systems

If coal combustion waste sites are close to public drinking water systems, there may be potential for human exposure through drinking water supplies. The location of public water supplies was determined through the use of the Federal Reporting Data System (FRDS), developed by EPA's Office of Drinking Water.

The FRDS data base provides the number of public water supply systems located within specified distances from a site and the populations using the systems. It should be noted that the FRDS data base locates water systems based on the centroid of the zip code of the mailing address of each utility and that the actual location of the intake or well may be different. This can cause some inaccuracy in the calculation of the distance and location of public drinking water supplies in relation to the waste site. In order to remedy potential inaccuracies and omissions, the locations of public water systems that appeared on topographical maps but were not reported by FRDS are also recorded.

Exhibit 5-26 shows the population served by public water systems located in the downgradient plume from the sites and within a five-kilometer radius. The exhibit also shows how many sites have no public water systems within a five-kilometer radius. Sixty-six percent of the sites have no public water systems within a five-kilometer radius. Fifteen percent of coal combustion sites have public water systems located within a five-kilometer distance and had systems which served over 5,000 people, and 19 percent have public water systems that serve fewer than 5,000 people.

The population data indicate that while there are often quite large populations in the vicinity of coal combustion waste sites, only 34 percent of the sites have public drinking water systems downgradient from the site.

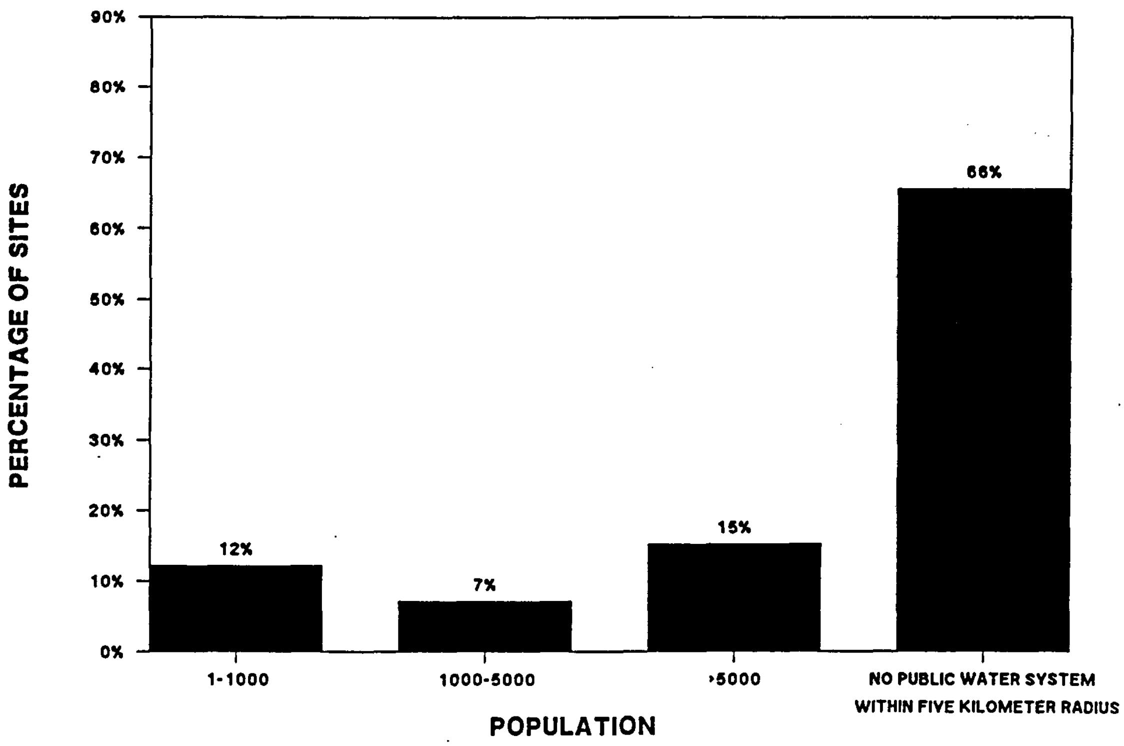
5.4.3 Ecologic Characteristics of Coal Combustion Waste Sites

Ecological data on endangered, threatened, or unique plants and animals is available through state Heritage Programs. The Nature Conservancy established the Heritage Programs, which now usually function as offices of state governments. The Heritage Programs develop and maintain data bases that describe jeopardized species and rare ecosystems within each state. It should be noted that there can be substantial variation in the completeness of data available from different states; some state Heritage Programs are fairly new, and basic data collection is still in its preliminary stages.

While it may not currently be possible to quantitatively model risk to ecosystems from coal combustion waste, the information provided by the Heritage Programs can indicate whether there are any jeopardized species near a specific

EXHIBIT 5-26

POPULATIONS SERVED BY PUBLIC WATER SYSTEMS NEAR WASTE SITES



SOURCE: ICF, based on FRDS data

waste site. If potentially hazardous constituents of coal combustion waste do migrate and produce environmental contamination, it could affect species and natural communities that are particularly vulnerable, thereby lessening ecosystem diversity.

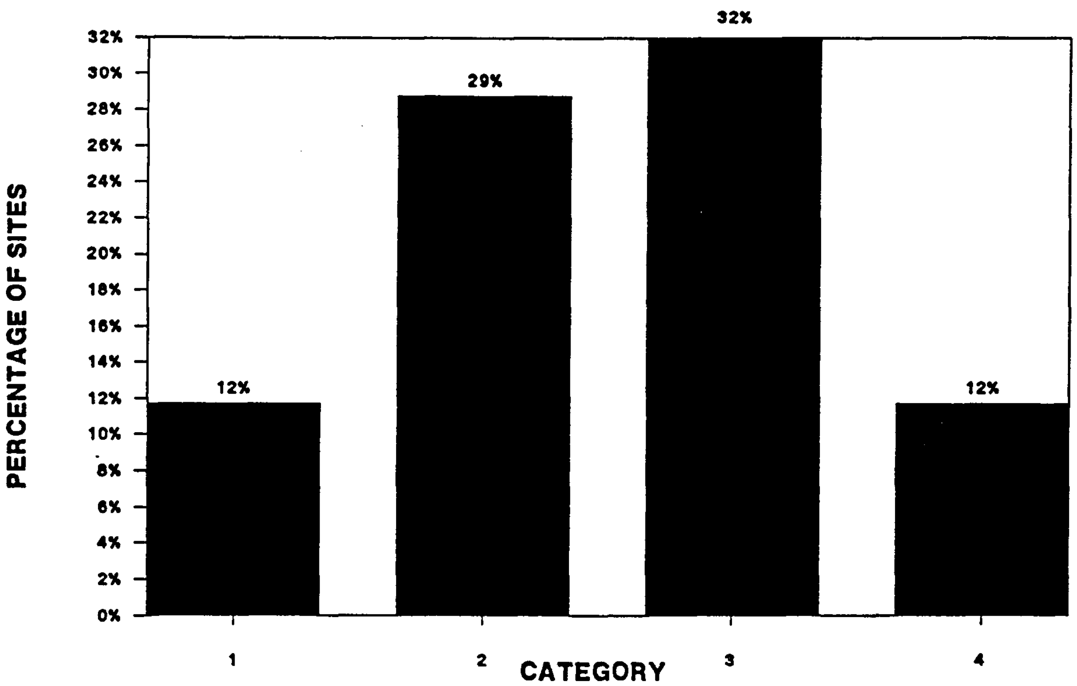
EPA provided Heritage Program staff with latitudes and longitudes for the sampled sites in states that had such programs. Using these coordinates, the Heritage Program staff performed a search of their data bases for rare or endangered species within a five-kilometer radius from the site.

The sample sites were grouped into four categories based on the results obtained from the Heritage Program. Category 1 includes sites having Federally designated threatened or endangered species within the five-kilometer radius. Category 2 includes sites that have no Federally designated threatened or endangered species within the five-kilometer distance, but which do contain species or natural communities designated by state Heritage Offices as critically endangered in that state. Category 3 contains sites for which there are species or natural communities of concern in the area. For sites in Category 4, there is no record of the existence of species of concern in the five-kilometer area.

Information was available on 85 of the 100 coal combustion waste sites in the sample. Exhibit 5-27 presents the breakdown of sites according to the categories described above. Twelve percent of the sites fall into Category 1, 29 percent in Category 2; 32 percent in Category 3; and 12 percent in Category 4 (no information was available for 15 percent).

EXHIBIT 5-27

ECOLOGICAL STATUS OF WASTE SITES



Category 1 : Federally designated plants or animals within a five km. radius
Category 2: Species of priority state concern within five km. radius
Category 3: species of concern to state environmental offices
Category 4: no data on ecosystem surrounding the site

SOURCE: ICF Inc., based on State Heritage Data

Given the high percentage of sites that have rare plant and animal communities within a five-kilometer radius supplies, and the proximity discussed earlier of waste disposal sites to surface-water bodies (which provide animals with drinking water), there could be a high potential for species exposure to coal combustion constituents.

5.4.4 Multivariate Analysis

The previous sections of this exposure analysis presented independent analyses of the population, environmental, and ecological characteristics of coal combustion waste sites. This section examines a number of these factors simultaneously in order to determine interactions that affect the overall potential for exposure from coal combustion waste sites.

As mentioned previously, only 34 percent of coal combustion waste sites (based on a random sample of 100 sites) have public drinking water systems in the downgradient plume within 5 kilometers of the waste site. Some of these public drinking water systems may use ground water that is currently treated before it is used as drinking water, indicating that human populations are unlikely to be directly exposed to any water that may be contaminated from coal combustion waste constituents. As discussed earlier, one reason for treating the water is ground-water hardness. Ground water that has a hardness greater than 240 ppm $CaCO_3$ is likely to be treated if it is used as a drinking water source. Of the 34 percent of the sites in the sample that have public water systems in the downgradient plume within 5 kilometers of the waste site, just under one-half of these sites have ground water with a hardness over 240 ppm $CaCO_3$. These results show that the potential for human exposure through drinking water is likely to be less than the proximity to public drinking water systems (FRDS data) indicates. Of all the sites sampled, only 18 percent have public drinking water systems within 5 kilometers and ground water under 240 ppm $CaCO_3$.[34]

The potential for human exposure through drinking water can be further evaluated by comparing the FRDS and ground-water quality characteristics with the hydrogeologic factors of net recharge and depth to ground water. Sites with a net recharge greater than 7 inches and a depth to ground water of fifteen feet or less are more likely to develop ground-water contamination due to waste leaching since water has a greater likelihood of contacting the coal combustion wastes. Of the 18 percent of the sites that have public water supplies and ground-water hardness below 240 ppm $CaCO_3$, two-thirds have a net recharge greater than 7 inches as well as a depth to ground water of 15 feet or less. Therefore, only 12 percent of the sites in the sample (18 percent x 2/3) have ground water that is likely to be used without treatment and hydrogeologic characteristics that indicate high potential for leachate migration.

This multivariate analysis of the factors affecting exposure at coal combustion waste sites illustrates the limited potential for human health risk through drinking water. Only 34 percent of the sites have public water systems within five kilometers and many of these public water systems are likely to treat the ground water due to hardness.

5.5 SUMMARY

This chapter has reviewed available information on the potential for coal-fired combustion wastes from electric utility power plants to affect human health and the environment. First, data on the potential corrosivity and EP toxicity of utility wastes was reviewed. After determining that coal combustion leachate sometimes contains hazardous constituents at levels above drinking water standards, the potential for this leachate to migrate from waste disposal sites was examined. Results of ground-water monitoring in several studies were interpreted and a number of compilations of "documented" damage cases were evaluated. After describing instances in which trace elements in coal combustion leachate have migrated from waste disposal sites, the potential effect of these migrations was examined. A sample of 100 utility waste disposal sites was selected, and these sites were evaluated in terms of population, environmental, and ecological characteristics to assess the potential for leachate migration and exposure of human and ecological populations.

Based on these data and analyses, several observations relating to potential dangers to human health and the environment can be made:

- If the current exemption from Subtitle C regulation were lifted for coal combustion wastes and these wastes were required to be tested for corrosivity or EP toxicity, most current waste volumes and waste streams would not be subject to hazardous waste regulation. The only waste stream which has had corrosive results is boiler cleaning waste. (Since coal ash is not aqueous, it cannot be corrosive.) For the other waste streams, available data indicate that while some of these waste streams could have high or low pH levels, they are not likely to fall under the RCRA definition of corrosive waste.

Similarly, while a few high-volume waste samples did exceed the EP toxicity limits for cadmium, chromium, and arsenic, this was limited to a few waste streams and represented only a small fraction of the samples for these waste streams (the chromium and arsenic exceedances were from only one fly ash sample). Available data on low-volume wastes showed that the only waste stream with significant RCRA exceedances was boiler cleaning waste, which had exceedances for chromium and lead. Wastewater brines were shown to exceed the RCRA standard for selenium in one sample. Results of EP tests on co-disposed wastes indicate that boiler cleaning wastes may not possess hazardous characteristics when co-disposed with ash. Results for all other waste streams and all other constituents were below EP toxicity limits.

- Results available from ground-water monitoring studies and documented cases of ground-water or surface-water contamination show some migration of PDWS constituents from utility waste disposal sites. In the most comprehensive and systematic of these studies, the Arthur D. Little survey of six utility sites, evidence of constituent migration downstream from the waste sites was conclusive only for cadmium. The Envirosphere ground-water study showed that only 3.7 percent of the samples showed downgradient concentrations of PDWS constituents that were higher than the concentrations of upgradient constituents (indicating that some contaminants are migrating from the site). This tends to support the results of the waste extraction tests. For the one utility disposal site on the National Priorities List, a site currently inactive since it was closed in 1974, the major ground-water contaminants were vanadium and selenium. However, this site differs from some other sites for which ground-water quality data are available in that wastes are from both coal and petroleum coke combustion.

- Although coal combustion waste leachate has the potential to migrate from the disposal area, the actual potential for exposure of human and ecological populations is likely to be limited. Because utility plants need a source of water to operate, most of the disposal sites are located quite close to surface water. Fifty eight percent of the 100 sample sites were within 500 meters of surface water. It is not common for drinking water wells to be located between the disposal site and the nearest downgradient surface water body. The effect of this proximity to surface water is that only 34 percent of the sampled sites had drinking water intakes within five kilometers. Furthermore, the flow of the surface water will tend to dilute the concentrations of trace metals to levels that satisfy drinking water standards.

- Simultaneously examining the environmental and population characteristics of coal combustion waste sites shows even less potential for exposure to human populations. 12 percent of the sites in the sample have public water systems within five kilometers of the site where the ground water may not be treated (i.e., ground-water hardness below 240 ppm $CaCO_3$) and hydrogeologic characteristics that indicate high potential for leachate migration.

CHAPTER 5

NOTES

1 See 40 CFR 261.21.

2 See 40 CFR 261.22. In using pH to determine corrosivity, EPA explained that "wastes exhibiting low or high pH can cause harm to human tissue, promote the migration of toxic contaminants from other wastes, and harm aquatic life."

3 These methods are set forth in 40 CFR 260.21 and 260.22.

4 See 40 CFR 261.23.

5 See 40 CFR 261.24.

6 See 40 CFR Part 261, Appendix II. These procedures for testing and the limits allowed for determining whether a waste is hazardous or not are currently under review.

7 A waste would be considered hazardous if it has been shown to have an oral LD 50 toxicity to rats of less than 50 mg/kg, an inhalation LC toxicity to rats of less than 2 mg/l, or a dermal LD 50 toxicity to rabbits of less than 2000 mg/kg.

8 See 40 CFR 261.11.

9 See CFR 40 Section 261.24. RCRA also establishes EP toxicity limits for six pesticides.

10 See CFR 40 Section 261, Appendix II.

11 Federal Register, Volume 51, No. 114, Friday, June 13, 1986, p. 21648.

12 Since the completion of the ASTM B tests discussed in this section, ASTM has dropped this extraction test (EPRI 1983).

13 Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EA-3236, September 1983.

14 Jackson, L. and Moore, F., Analytical Aspects of the Fossil Energy Waste Sampling and Characterization Project, prepared for the U.S. Department of Energy, Office of Fossil Energy, DOE/LC/00022-1599 (DE84009266), March 1984.

15 Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-fired Electric Generation Plants, prepared for the Air and Energy Engineering Research Laboratory of the U.S. Environmental Protection Agency for the Office of Solid Waste, EPA-600-7-85-028, June 1985.

16 Mason, B.J., and Carlile, D.W., draft report of Round Robin Evaluation for Selected Elements and Anionic Species from TCLP and EP Extractions, prepared by Battelle Pacific Northwest Laboratories, for the Electric Power Research Institute, EPRI EA-4740, April 25, 1986.

17 Battelle's test varied from standard TCLP procedure by allowing 14 days, rather than the normal 7, for the completion of the test.

18 Electric Power Research Institute, "Mobilization and Attenuation of Trace Elements in an Artificially Weathered Fly Ash," prepared by the University of Alberta, Edmonton, Canada, EPRI EA-4747, August 1986.

19 Battelle Pacific Northwest Laboratories, Chemical Characterization of Fossil Fuel Combustion Wastes, prepared for the Electric Power Research Institute, September 1987.

20 Radian Corporation, Characterization of Utility Low-Volume Wastes, prepared for the Electric Power Research Institute, May 1985.

21 Radian Corporation, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared for the Electric Power Research Institute, July 1987.

22 Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-fired Electric Generation Plants, prepared by the Air and Energy Engineering Research Laboratory of the U.S. Environmental Protection Agency, for the Office of Solid Waste, EPA-600-7-85-028, June 1985.

23 Franklin Associates, Ltd., Survey of Ground-water Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for U.S. Environmental Protection Agency, March 1984.

24 Envirosphere Company, "Report on the Ground Water Data Base Assembled by the Utility Solid Waste Activities Group," in Utility Solid Waste Activities Group (USWAG), Report and Technical Studies on the Disposal and Utilization of Fossil·Fuel By-Products, October 26, 1982, Appendix C.

25 It is not necessarily true that measurements taken from upgradient and downgradient wells at approximately the same time yield comparable measurements. In fact, due to migration time, there will be a lag between the time of comparable upgradient and downgradient measurements.

26 Envirosphere Company, Op. cit., p. 38. These percentage numbers do not correspond precisely to the data in Exhibit 5-11 because Envirosphere normalized the data it received from the utilities so that each facility would be weighted evenly (i.e.,, a facility with many more measurements would not be weighted excessively). Envirosphere reports that 1.7 percent of the normalized data had upgradient measurements lower than the PDWS and the downgradient higher than the PDWS; 5 percent of the data indicated that both values exceeded the standard.

27 Envirosphere Company, Environmental Effects of Utility Solid Waste Disposal, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, July 1979.

28 Dames & Moore, "Review of Existing Literature & Published Data to Determine if Proven Documented Cases of Danger to Human Health and the Environment Exist as a Result of Disposal of Fossil Fuel Combustion Wastes", in Utility Solid Waste Activities Group (USWAG), Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix B.

29 Cherkauer, D. S. "The Effect of Fly Ash Disposal on a Shallow Ground-Water System." Ground Water, Vol. 18, No. 6, pp. 544-550, 1980.

30 Groenewold, G. H., and B. W. Rehm. "Applicability of Column Leaching Data to the Design of Fly Ash and FGD Waste Disposal Sites in Surface- Mined Areas." In Proceedings of the Low-Rank Coal Technology Development Workshop, comp. Energy Resources Company, Inc., DOE/ET/17086-1932, CONF-8106235; Washington, D.C., U.S. Department of Energy, Technical Information Center, pp. 3-79 - 3-95, 1981.

31 Envirosphere Company, Environmental Settings and Solid-Residues Disposal in the Electric Utility Industry; prepared for the Electric Power Research Institute, August 1984.

32 Linda Aller, Truman Bennet, Jay H. Laher, Rebecca J. Betty, A Standardized System for Evaluating Ground Water Pollution Potential Using Hydrologic Settings, prepared by the National Well Water Association for U.S. EPA Office of Research and Development, Ada, OK, May 1985. EPA 600-285-018.

33 Veronica T. Pye, Ruth Patrick, John Quarles, Ground Water Contamination in the United States, Philadelphia: University of Pennsylvania Press, 1983.

34 Ground water over 180 ppm CaCO3 may also be treated. Of the 34 percent of the sites in the sample that have public water systems in the plume downgradient from the site within 5 kilometers, 73 percent have ground water with a hardness over 180 ppm CaCO3. Therefore, only 9 percent of the sites in the sample have both public water systems within 5 kilometers and ground water under 180 ppm CaCO3. Since many public water systems may not treat water in the range of 180-240 ppm CaCO3, the discussion in the report focuses only on ground water in excess of 240 ppm CaCO3. This is a conservative assumption since the water may be treated, either by the public authority or the private homeowner. In all cases, the extent of exposure through private wells would have to be evaluated on a site-by-site basis.

CHAPTER SIX

ECONOMIC COSTS AND IMPACTS

Section 8002(n) of RCRA requires that EPA's study of coal combustion wastes examine "alternatives to current disposal methods," "the costs of such alternatives," "the impact of those alternatives on the use of coal and other natural resources" and "the current and potential utilization of such materials." In response to these directives this chapter examines the potential costs to electric utilities if coal-fired combustion waste disposal practices are regulated differently than they are currently.

The first section of this chapter (Section 6.1) examines the costs incurred by electric utilities using current disposal methods for coal combustion wastes.[1] Section 6.2 follows with a discussion of the costs that could be incurred if coal combustion wastes were regulated differently than they are today. These costs include the costs of implementing alternative waste management practices and the costs of additional administrative responsibilities that would be incurred. Section 6.3 examines how new regulations might affect the cost of utilizing coal combustion wastes in various by-product applications. The last section of this chapter (Section 6.4) considers how energy use patterns in the electric utility industry might change if alternative waste management practices that significantly affect the cost of generating electricity with coal were imposed.

6.1 WASTE DISPOSAL COSTS ASSOCIATED WITH CURRENT DISPOSAL METHODS

The management of utility wastes comprises a series of activities -- from initial waste collection to disposal. These current waste management activities can be classified into five basic components:[2]

1. **Waste Handling and Processing.** This is the initial phase of the disposal process, involving collection of the various waste products after they have been generated and initial treatment of the wastes to prepare them for final disposal.

2. **Interim Waste Storage at the Plant.** Some waste products that are dry when produced, such as fly ash or flue gas desulfurization (FGD) wastes from dry scrubbers, often require interim storage prior to final disposal.

3. **Raw Materials Handling and Storage.** Some disposal processes involve stabilization or chemical fixation of the waste to prepare it for disposal. The raw materials used for this phase, including additives such as lime, Calcilox, and basic fly ash, often require special handling and storage facilities.

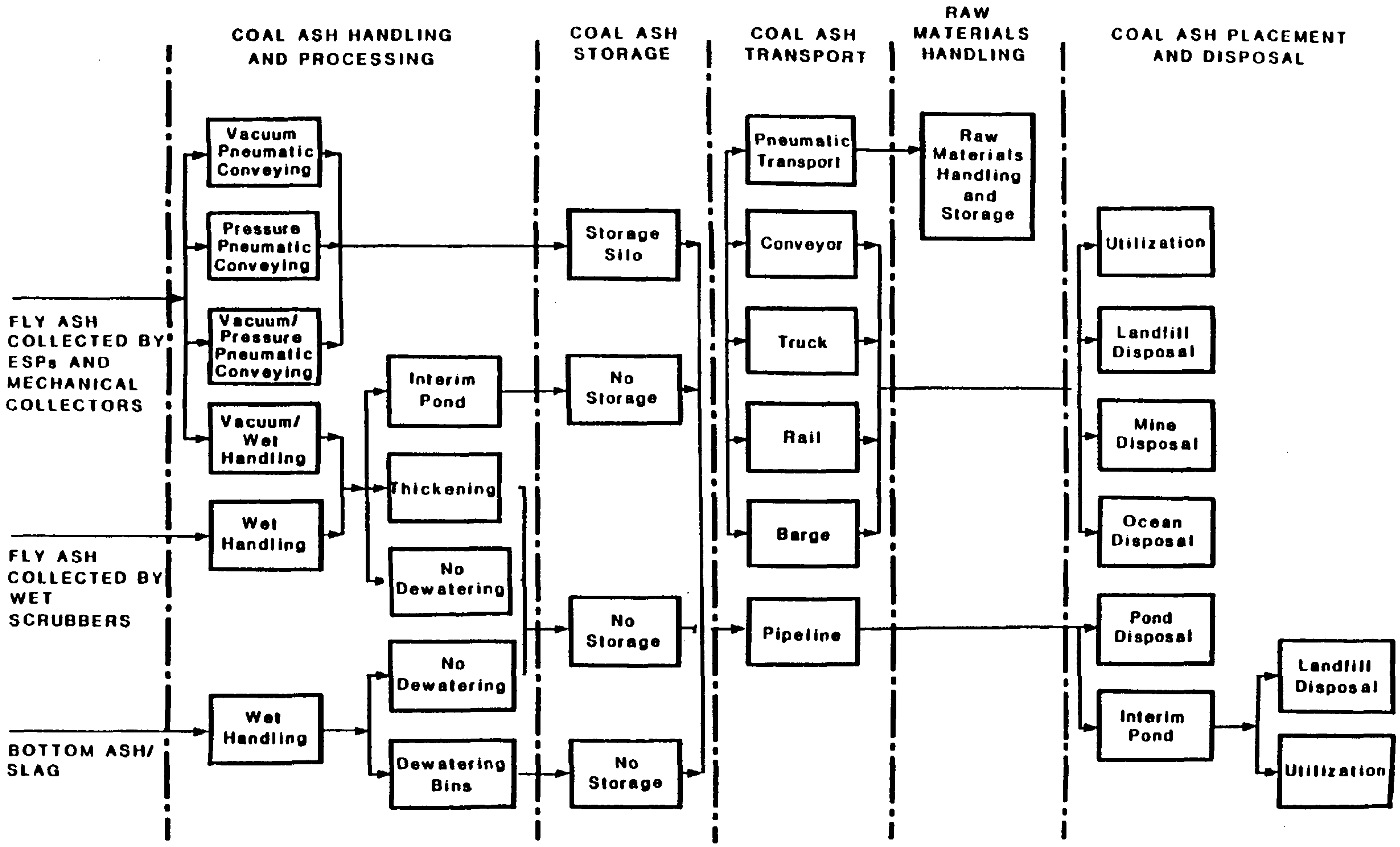
4. **Waste Transport to a Disposal Facility.** Environmentally sound disposal requires careful transportation of the waste to the disposal site. Many modes of transportation can be used, including trucks, railroads, barges, pipelines, and conveyor systems.

5. **Waste Placement and Disposal.** This is the final stage of the waste disposal chain. It involves placing the waste in a suitable waste management facility (usually a surface impoundment or landfill) and all activities required after the facility is closed. Alternatively, the final disposition of a waste product may entail utilization of the waste in various applications (such as cement production or sandblasting operations).

Exhibit 6-1 presents a schematic illustration of the current waste management and disposal options for coal ash; Exhibit 6-2 illustrates the options available for FGD wastes. The waste management costs discussed in this

Exhibit 6-1

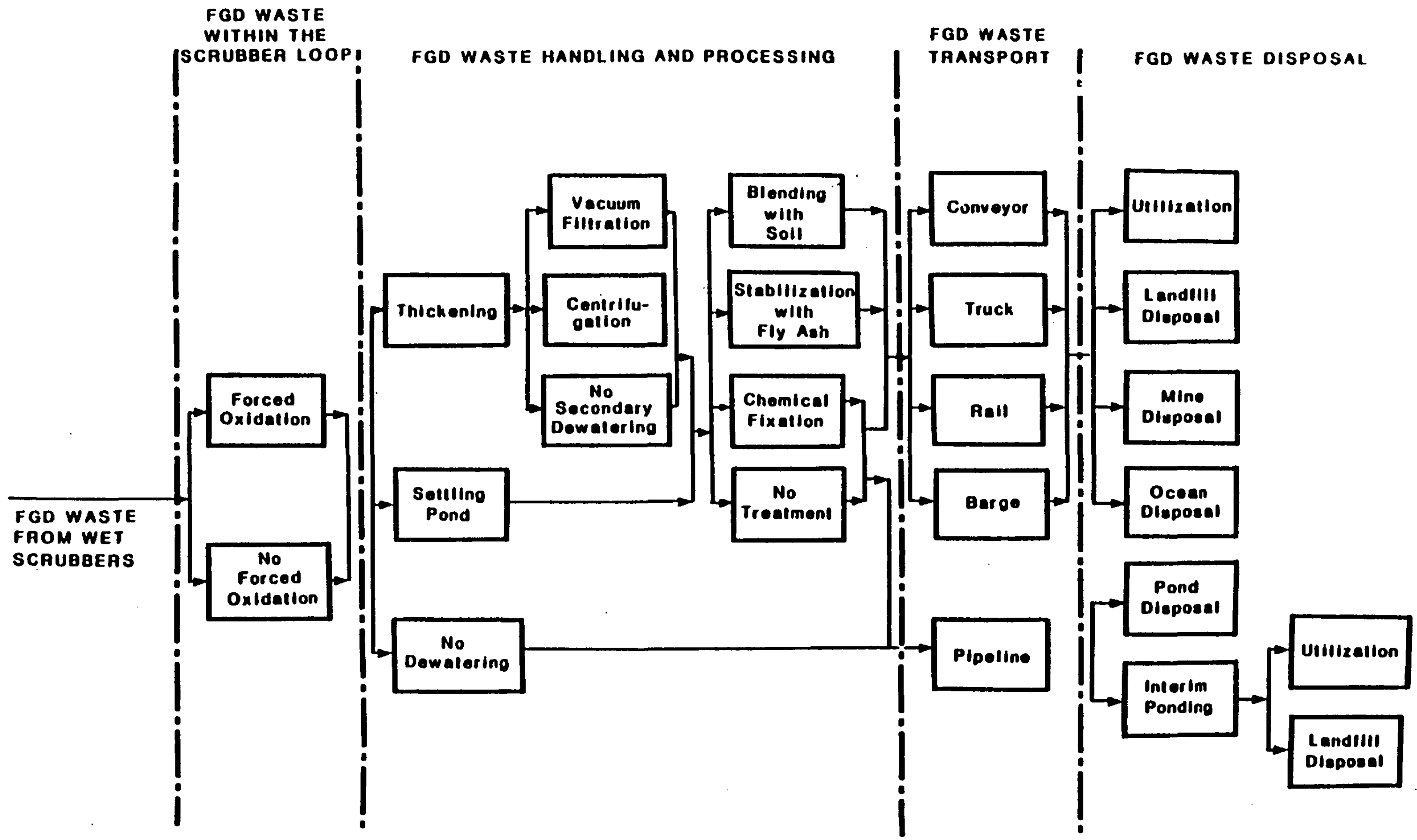
Overview of Waste Handling and Disposal Options for Coal Ash



Source: Arthur D. Little, Inc., *Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants*, June 1985.

Exhibit 6-2

Overview of Waste Handling and Disposal Options for FGD Waste



Source: Arthur D. Little, Inc., *Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants*, June 1985.

chapter are those associated with the last component of waste management (i.e., waste placement and disposal). These are the costs associated with actual construction of the waste management facility and placement of the wastes into the facility. If current practices for managing coal-fired wastes from electric utilities are altered, it is this final stage in waste management that would probably be most affected. However, as will be explored later in this chapter, some regulatory alternatives may affect other aspects of waste management.

6.1.1 Costs of Waste Placement and Disposal

The wastes from coal-fired combustion at electric utility power plants are often mixed together in the same waste management facility, typically a surface impoundment or landfill. Although surface impoundments were once the preferred method, and are still widely used, landfilling has become the more common practice because less land is required, and it is usually more environmentally sound (because of the lower water requirements, reduced leaching problems, etc.).

The costs of waste disposal can vary substantially. Exhibit 6-3 shows representative capital costs associated with constructing surface impoundments and landfills for coal-fired electric utility wastes. Exhibit 6-4 shows total costs (i.e., annualized capital costs plus operation and maintenance expenses).[3] Costs are shown for power plants that range in size from 100 to 3000 megawatts (Mw); power plants that fall outside of this range may incur

EXHIBIT 6-3

RANGES OF AVERAGE CAPITAL COSTS ASSOCIATED WITH COAL-FIRED ELECTRIC UTILITY WASTE DISPOSAL (4th quarter 1986 dollars per kilowatt)

	Size of Power Plant			
Type of Waste	100 MW	500 MW	1000 MW	3000 MW
Landfills				
Fly Ash	9-14	4-7	3-5	2-3
Bottom Ash	2- 5	2-3	1-2	1-1.3
FGD Waste	6-13	4-7	3-6	2-4
Surface Impoundments				
Fly Ash	27-50	15-27	13-23	10-18
Bottom Ash	10-20	6-11	5- 9	3- 6
FGD Waste	14-30	10-19	9-17	7-14

Source: Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants, EPA 600/7-85-028, June 1985.

EXHIBIT 6-4

RANGES OF AVERAGE TOTAL COSTS FOR COAL-FIRED ELECTRIC UTILITY WASTE DISPOSAL (4th quarter 1986 dollars per ton)*

	Size of Power Plant			
Type of Waste	100 MW	500 MW	1000 MW	3000 MW
Landfills				
Fly Ash	9-18	6-11	5-9	2-6
Bottom Ash	10-16	5-9	4-8	2-6
FGD Waste	4-10	4-7	3-6	2-4
Surface Impoundments				
Fly Ash	17-31	9-17	8-14	5-8
Bottom Ash	11-26	8-15	7-13	5-8
FGD Waste	8-17	7-13	6-10	5-7

* Dollar per ton estimates are based on the amount of waste produced each year. For purposes of this illustration, a power plant is assumed to generate annually 308 tons of fly ash per megawatt (MW), 77 tons of bottom ash per MW, and 264 tons of FGD waste per MW. Amounts will vary depending on coal quality, FGD technology, and boiler type, among other factors.

Source: Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants, EPA 600/7-85-028, June 1985.

different waste management costs. Both capital costs and total costs are shown for unlined facilities without ground-water monitoring or leachate control systems. The major factors affecting the cost of waste management are discussed below.

The amount of capital costs for a waste management facility can be attributed primarily to three factors: site preparation, excavation, and construction of containment structures.[4] Capital costs can be substantially reduced if the amount of earthwork can be minimized. Capital costs for surface impoundments, for example, increase significantly if dike construction or excavation is required. However, if existing site features can be used, such as valleys or abandoned pits, capital costs will be lower. Similarly, capital costs for landfills that require little excavation are lower than for those sites requiring extensive earthwork.

As Exhibit 6-3 illustrates, landfills are far less capital intensive than surface impoundments. For example, capital costs for fly ash placement in a surface impoundment at a 500 MW power plant would range from approximately $15 to $27 per kilowatt.[5] In contrast, capital costs for landfills range from about $4 to $7 per kilowatt. Landfills tend to cost less than impoundments primarily because the area required for a given amount of waste is less, and neither dikes nor piping and pumping systems are necessary.

Annual costs for landfills (see Exhibit 6-4) also tend to be less than those for surface impoundments primarily because landfills tend to be far less capital intensive. For example, costs for fly ash management at a 500 MW power plant range from about $9 to $17 per ton when the wastes are placed in surface impoundments, while the comparable range at a landfill is about $6 to $11 per ton. Similarly, the cost for bottom ash disposal at an impoundment for a 500 MW power plant ranges from $8 to $15 per ton, while the costs to dispose in a landfill range from about $5 to $9 per ton.

Other factors that affect the cost of utility waste disposal include

- **Size of the Power Plant.** Because larger power plants consume more coal than smaller facilities, they generate more waste material. However, more efficient operating procedures allow a larger disposal site to realize economies of scale not available at smaller sites; thus, the cost per ton of waste disposed is typically less.

- **Rate of Operation.** The number of hours that a coal-fired power plant operates varies from plant to plant, ranging from fewer than 3,500 hours per year to more than 6,500 hours. As operating levels increase, the amount of waste generated will increase as more coal is burned to meet the higher generation load.

- **Type of Coal.** The quantity of ash produced is proportional to the ash content of the coal, which ranges from 5 to 20 percent on average. Also, the grade of coal and boiler design will affect the relative proportions of fly ash and bottom ash (see Chapter Three for a discussion of the impact of boiler design on types and amount of wastes generated).

- **FGD Equipment.** Because of the additional materials used in flue gas desulfurization, a power plant that uses this process to remove sulfur dioxide generates substantially more waste than does a power plant with no sulfur dioxide controls. The amount of waste generated also varies from one FGD operation to the next, primarily because of differences in sulfur content among the various coals and, to a lesser extent, because of the type of FGD process employed.

For the few power plants currently disposing their waste in mines or quarries, this disposal method has been economic because of convenient access to the disposal site. Since much of the excavation normally required at a disposal site has already been performed as a result of the mining or quarrying operation, waste disposal costs can be quite competitive with costs associated with more traditional methods of disposal. The cost of disposing in mines or quarries for power plants that do not have easy access to the mine or quarry could quickly become prohibitive due to the costs of arranging for disposal at a remote site and of transporting the waste. Costs are also affected by whether or not the mine or quarry is still operating, whether the mining was surface or underground, and the amount of additional preparation required to dispose of the wastes, among other factors.

The costs of ocean disposal are not well known because there has been limited experience with this disposal method. Ocean disposal has been considered for unconsolidated waste (i.e., waste material that has not been physically or chemically altered prior to disposal)[6] and for more stabilized forms of waste, such as blocks for artificial reef construction;[7] however, this method has been attempted only for projects such as artificial reef construction, and then only on a trial basis. The most critical factors that would affect the magnitude of costs for ocean disposal are the availability of ash-handling facilities to load ocean-going vessels, the ability to gain easy access to the necessary waterways, and the physical characteristics of the wastes intended for disposal.

Because neither ocean disposal nor mine or quarry disposal is likely to be used on a widespread basis, they have been discussed here only briefly; see Chapter Four for a more detailed discussion of these two disposal options.

6.1.2 Costs Associated with Lined Disposal Facilities

The waste management costs presented above for surface impoundments and landfills do not include the cost of natural or synthetic liners to control the flow of leachate from the disposal area. Traditionally, most waste management sites, both surface impoundments and landfills, have not been lined to retard leaching, although this practice has become more widespread in recent years (see Chapter Four for a detailed discussion of liners). Currently, about 25 percent of all coal combustion waste management sites employ some type of liner system. Most liners are made of clay, synthetic materials, or stabilized utility waste.

Clay is used as a liner material because it is not very permeable, although its permeability will vary depending on the nature of the clay and the degree of compaction. Because clay is expensive to transport, the costs of the various clays used for liner material are directly related to the local availability of the clay. The installed cost of clay liners can range from $4.45 to $15.75 per cubic yard.[8] For a liner 36-inches thick, (liner thicknesses do vary), this results in a cost range of $21,000 to $75,000 per acre, or about $0.70 to $2.55 per ton of waste disposed in a landfill and $2.25 to $8.20 per ton for waste placed in an impoundment for a 500 MW power plant.[9]

Synthetic liner materials come in two basic varieties--exposable and unexposable. The membranes of exposable liners are resistant to degradation from exposure to the elements even if the liner is left uncovered. The membranes of unexposable liners will not function properly if the liner is exposed. Costs for installing exposable liners range from $43,000 to $113,000 per acre, or $1.45 to $3.85 per ton of waste disposed in landfills and from

$4.70 to $12.35 per ton of waste placed in surface impoundments.[10] Costs to install unexposable liners range from $59,000 to $123,000 per acre, or $2.00 to $4.15 per ton of waste disposed in landfills and $6.45 to $13.45 per ton placed in impoundments.[11] The ranges of costs are due primarily to differences in the cost of the material, differences in liner thickness, and allowances for various site-specific costs.

Stabilized utility waste, made from combinations of various ash wastes (such as fly ash or bottom ash), FGD waste, and lime, may be used as liner material when the required materials are available at the plant site. At an installed cost of about $13.70 per cubic yard, liners ranging from 3 feet to 5 feet in thickness can be constructed for $66,000 to $110,000 per acre,[12] which corresponds to total capital costs of $3.0-$5.0 million at a landfill, or about $2.25 to $3.75 per ton of disposed waste from a 500 Mw power plant. Total capital costs at impoundments would be $9.6-$16.0 million, or $7.20-$12.00 per ton of waste managed.[13]

6.2 COSTS OF ALTERNATIVE DISPOSAL OPTIONS

As described above, coal-fired utility wastes are currently exempt from RCRA Subtitle C waste management requirements. In the interim, coal combustion wastes are regulated under state statutes and regulations (see Chapter Four). If these wastes are subject to Subtitle C regulation, the incremental costs will depend on the regulatory option(s) ultimately selected. Section 6.2.1 outlines the major regulatory alternatives and discusses the flexibility allowed EPA under RCRA to promulgate regulations that account for the special nature of coal combustion wastes. Section 6.2.2 presents cost estimates for individual

Subtitle C disposal requirements, and Section 6.2.3 presents cost estimates for three regulatory scenarios if coal combustion wastes are regulated under Subtitle C.

6.2.1 Regulatory Alternatives under Subtitle C

As described in Chapter Five, there are two ways in which coal combustion wastes could be identified as hazardous and thus subject to requirements outlined in Part 264 of RCRA: the characteristic procedure and the listing procedure.

- **Regulation As Characteristic Waste.** Unless otherwise exempted, solid wastes are hazardous under RCRA if they display any of four characteristics: ignitibility, corrosivity, reactivity, or EP toxicity. Coal combustion wastes are unlikely to be ignitable or reactive, but could be corrosive (for aqueous wastes) or EP toxic. Subtitle C regulations would apply only to those waste streams that exhibited any of the hazardous characteristics. As discussed in Chapter Five, it is likely that only a small percentage of all waste generated would be hazardous. However, since some low volume wastes may be corrosive, this could have an impact on utilities that currently co-dispose high- and low-volume wastes. In these cases, the utility could either stop co-disposing or the landfill would have to conform to Subtitle C standards. In the case of surface impoundments, it might still be possible to co-dispose high- and low-volume wastes if the disposal impoundment met the requirements for a neutralization surface impoundment as set forth in 47 FR 1254, January 11, 1982.

- **Regulation as Listed Waste.** In addition to regulation under Subtitle C as characteristic waste, the Administrator may list a waste as hazardous under RCRA if it meets any of the three criteria contained in 40 CFR 261.11: (1) the waste exhibits any of the four characteristics described above; (2) it has been found to be fatal to humans in low doses or is otherwise measured as acutely hazardous; or (3) it contains any of the toxic constituents listed in Appendix VIII of Part 261. The Administrator does not have to list a waste that contains any of the toxic constituents listed in Appendix VIII if the Agency concludes that "the waste is not capable of posing a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported or disposed of, or otherwise managed". The Administrator could decide to list as hazardous all coal combustion waste streams or only selected ones.

If Subtitle C regulation is warranted for coal combustion wastes, all the requirements for hazardous waste treatment, storage, disposal, and recycling facilities in 40 CFR 264 could be applied to the wastes from coal-fired power plants. Since coal combustion waste is mainly managed in surface impoundments and landfills, the requirements of Subparts A-H, K, and N would apply. In general, the required activities include the following:

- **General Facility Standards.** Facilities must apply for an identification number, prepare required notices when necessary, perform general waste analysis, secure the disposal facility to prevent unauthorized entry, comply with general inspection requirements, provide personnel training, and observe location standards (these include a provision that facilities located in a 100-year flood plain must be designed, constructed, operated, and maintained to prevent washout of any hazardous waste by a 100-year flood). (40 CFR 264 Subpart B)

- **Preparedness and Prevention.** Hazardous waste facility operators must design and operate facilities to minimize the possibility of fire or explosion, equip the facility with emergency equipment, test and maintain the equipment, and provide EPA and other government officials access to communications or alarm systems. (40 CFR 264 Subpart C)

- **Contingency Plan and Emergency Procedures.** The facility operators must have a contingency plan to minimize hazards to human health or the environment in the event of fire or explosion. (40 CFR 264 Subpart D)

- **Manifest System, Recordkeeping, and Reporting.** Hazardous waste facility operators must maintain a manifest system, keep a written operating record, and prepare a biennial report. (40 CFR 264 Subpart E)

- **Ground-water Protection.** Unless a waste management facility meets certain standards,[14] a Subtitle C facility is required to comply with requirements to detect, characterize, and respond to releases from solid waste management units at the facility. These requirements include ground-water monitoring and corrective action as necessary to protect human health and the environment. (40 CFR 264 Subpart F)

- **Closure and Post-closure.** Subtitle C facilities must comply with closure and post-closure performance standards to minimize the risk of hazardous constituents escaping into the environment. (40 CFR 264 Subpart G)

- **Financial Requirements.** Subtitle C facilities must establish a financial assurance plan for closure of the facility and for post-closure care. Possible methods of financial assurance include a closure trust fund, surety bonds, closure letter of credit, closure insurance, or financial test and corporate guarantee.[15] (40 CFR 264 Subpart H)

- **Design and Operating Requirements.** Unless granted an exemption, new surface impoundments or landfills or new units at existing impoundments or landfills must install two or more liners and a leachate collection system between the liners. (40 CFR 264 Subparts K and H)

In recognition of the special nature of coal combustion wastes, Congress afforded EPA some flexibility in designing regulations for coal combustion wastes if they are subject to regulation under Subtitle C. This flexibility allows EPA to exempt electric utilities from some regulations imposed on owners and operators of hazardous waste treatment, storage, and disposal facilities by the Hazardous and Solid Waste Amendments of 1984. Specifically, section 3004(x) of RCRA allows the Administrator to modify the following requirements when promulgating regulations for utility waste.

- Section 3004 (c) prohibits the placement of uncontained liquids in landfills;
- Section 3004 (d) prohibits the land disposal of specified wastes;[16]
- Section 3004 (e) prohibits the land disposal of solvents and dioxins;
- Section 3004 (f) mandates a determination regarding disposal of specified wastes into deep injection wells;
- Section 3004 (g) mandates determinations on continued land disposal of all listed hazardous wastes;
- Section 3004 (o) lists minimum technical requirements for design and operation of landfills and surface impoundments, which specify the installation of two or more liners, a leachate collection system, and ground-water monitoring;
- Section 3004 (u) requires the Administrator to promulgate standards for facilities that burn hazardous waste as fuel; and
- Section 3005 (j) provides that interim-status surface impoundments must also meet minimum technical requirements specified in section 3004 (o).

In addition to the flexibility afforded by 3004 (x), it is possible for EPA to modify any of the standards applicable to waste treatment and disposal facilities if lesser standards are protective of human health and the environment. Section 3004 (a) states "... The Administrator shall promulgate regulations establishing such performance standards, applicable to owners and operators of facilities for the treatment, storage, or disposal of hazardous waste identified or listed under this subtitle, as may be necessary to protect human health and the environment."

There remains substantial uncertainty, however, about the extent to which, in practice, the statutory language of Subtitle C would provide sufficient flexibility to design a waste management program appropriate for high-volume, low-toxicity coal combustion wastes. EPA may also consider waste management requirements, as needed, under the current Subtitle D provisions for solid wastes, or may seek appropriate additional authorities.

6.2.2 Cost Estimates for Individual RCRA Subtitle C Disposal Standards

If EPA determines that Subtitle C regulation is warranted for coal combustion wastes, there is a wide range of regulatory options that could be undertaken. Required activities could consist of some, all, or variations of the requirements listed in 40 CFR Subparts B-H (and described briefly in Section 6.2.1). This section presents estimates for the costs that would be associated with compliance with individual Subtitle C requirements.

6.2.2.1 General Facility Standards; Preparedness and Prevention; Contingency Plan and Emergency Procedures; and Manifest System

Subparts B through E in Part 264 of the RCRA regulations list general requirements for such activities as preparing written notices and plans for submission to EPA; conducting waste analyses; providing security at the disposal site; and recordkeeping and reporting. Many of these activities would be undertaken during the permitting process, which is set forth in Part 270 of RCRA.

The Part B application must contain the technical information listed in Part 264 B through E. The cost to the electric utility industry to prepare a Part B permit application was estimated in a study done for the Utility Solid Waste Activities Group (USWAG), which calculated that the total cost of submitting

Part B permit analyses would be $721,000 per plant, or about $0.55 per ton of waste disposed.[17] The industry cost, if all power plants filed Part B applications, would be about $370 million, or about $54 million in annualized costs.

Location standards are also specified under Subpart B of Part 264 of RCRA. One such standard is for facilities located in a 100-year flood plain. Part 246.16(b) requires protective measures to prevent washout from flooding.

USWAG estimated the costs for protecting waste disposal facilities located within a 100-year flood plain to be about $740 per acre for surface impoundments and about $1,100 per acre for landfills on an annualized basis.[18] This corresponds to waste management costs of approximately $0.55 per ton of waste at surface impoundments and $0.25 per ton at landfills.[19] Industry-wide costs for flood protection at all impoundments are estimated to be about $92 million for capital expenditures (about $13 million in annualized costs); costs for flood protection at all landfills would be about $146 million for capital expenditures (about $20 million in annualized costs).[20]

6.2.2.2 Ground-water Protection

Subpart F of 40 CFR Part 264 lists requirements for ground-water monitoring systems. The costs of installing and maintaining an acceptable ground-water monitoring program are dependent on the number of monitoring wells required and the frequency of testing. The study conducted by Arthur D. Little for EPA estimated that capital costs for installing six monitoring wells at a facility would range from $18,000 to $25,000.[21] At a sampling frequency of four times per year, annual operating and maintenance costs would be $10,000 to $14,500. Total ground-water monitoring costs would range from $0.06 to $0.10 per ton of managed waste. In another study conducted for USWAG by Envirosphere, which used different well configurations and cost parameters, somewhat higher costs ($0.10-$0.12 per ton of waste managed) were estimated.[22]

It is not known how many coal-fired power plants currently have adequate ground-water monitoring systems in place. To estimate industry-wide costs, EPA has conservatively assumed that all power plants would be required to install new ground-water monitoring systems. Using the costs developed in the Arthur D. Little study, EPA calculated that total capital costs would be about $9.3 to $12.8 million. Total annualized costs would range from $6.5 to $9.3 million.

6.2.2.3 Corrective Action

Subpart F of 40 CFR Part 264 also lists requirements for corrective action. A variety of actions may be undertaken to correct ground-water contamination problems caused by a hazardous waste disposal facility. The facility owner or operator would need to conduct a site-specific investigation to ascertain the potential degree of contamination and the appropriate response that would be most effective in remedying the situation. Types of remedial responses that might be required would be placing a cap (made of either a clay or synthetic material) on the disposal unit, counter-pumping the ground water to retard contaminant migration, excavating the disposal area and removing the wastes to a Subtitle C landfill, or installing an impermeable curtain around the disposal area to prevent ground-water flow into or out of the disposal area. As one example of the potential magnitude of corrective action costs, this section evaluates the cost to excavate the existing disposal areas and transfer the wastes to RCRA Subtitle C-approved facilities.

EPA developed the following formula to calculate total excavation costs for Subtitle C units, (including closure of the existing site and removal of the wastes to a Subtitle C facility):

Cost = [(Surface Area x $45) + (Volume x $187)] x 2.16

where the surface area is measured in square meters, and volume is measured in cubic meters.[23]

For a power plant of average size (500 MW), it has been assumed that a 45-acre landfill would be required, or about 182,000 square meters, with a capacity of approximately 5 million cubic meters. Based on the cost equation listed above, costs for excavation and waste transfer for a landfill site would be about $2.0 billion.[24] For surface impoundments, the appropriate parameters are 145 acres, or about 587,000 square meters, and a volume of about 5 million cubic meters, which works out to about $2.1 billion for the same type of corrective action. If this type of corrective action were required at all power plants, compliance costs for the industry would be enormous. At a cost of about $2 billion per plant, industry-wide costs would exceed one trillion dollars.

6.2.2.4 Closure and Post-closure

Subpart G of 40 CFR 264 specifies general closure and post-closure requirements for Subtitle C facilities and 40 CFR 264(K) and (N) list specific requirements for closure and post-closure care of surface impoundments and landfills, respectively. These requirements, as applied to coal combustion wastes, would require the dewatering of ash ponds, installation of a suitable cover liner made of synthetic materials, application of topsoil to support vegetation, seeding and fertilizing, installation of security fencing, and long-term ground-water monitoring. USWAG estimates that capital costs for closing a waste management facility range from $39,000 to $128,000 per acre for surface impoundments and from $55,000 to $137,000 per acre for landfills.[25] Once the facility is closed, additional costs would be incurred for post-closure care -- about $1,050 per acre annually.[26] Total annual costs for closure of a surface impoundment would range from about $1.0 to $2.8 million for a typical 500 Mw power plant, or $5.00 to $14.75 per ton of waste managed. For a landfill, total annual costs would range from $0.4 to $0.9 million, or $2.10 to $4.90 per ton.[27].

An owner or operator that chooses to close a facility in the event that coal combustion wastes are brought under Subtitle C regulation would not necessarily have to follow the closure and post-closure requirements for hazardous waste facilities listed in 40 CFR Part 264. If regulations are proposed, there would be some period of time before final regulations take effect.[28] If the disposal facility is closed during this interim period, the closure standards that would apply would be those required under state regulations, not Subtitle C regulations.

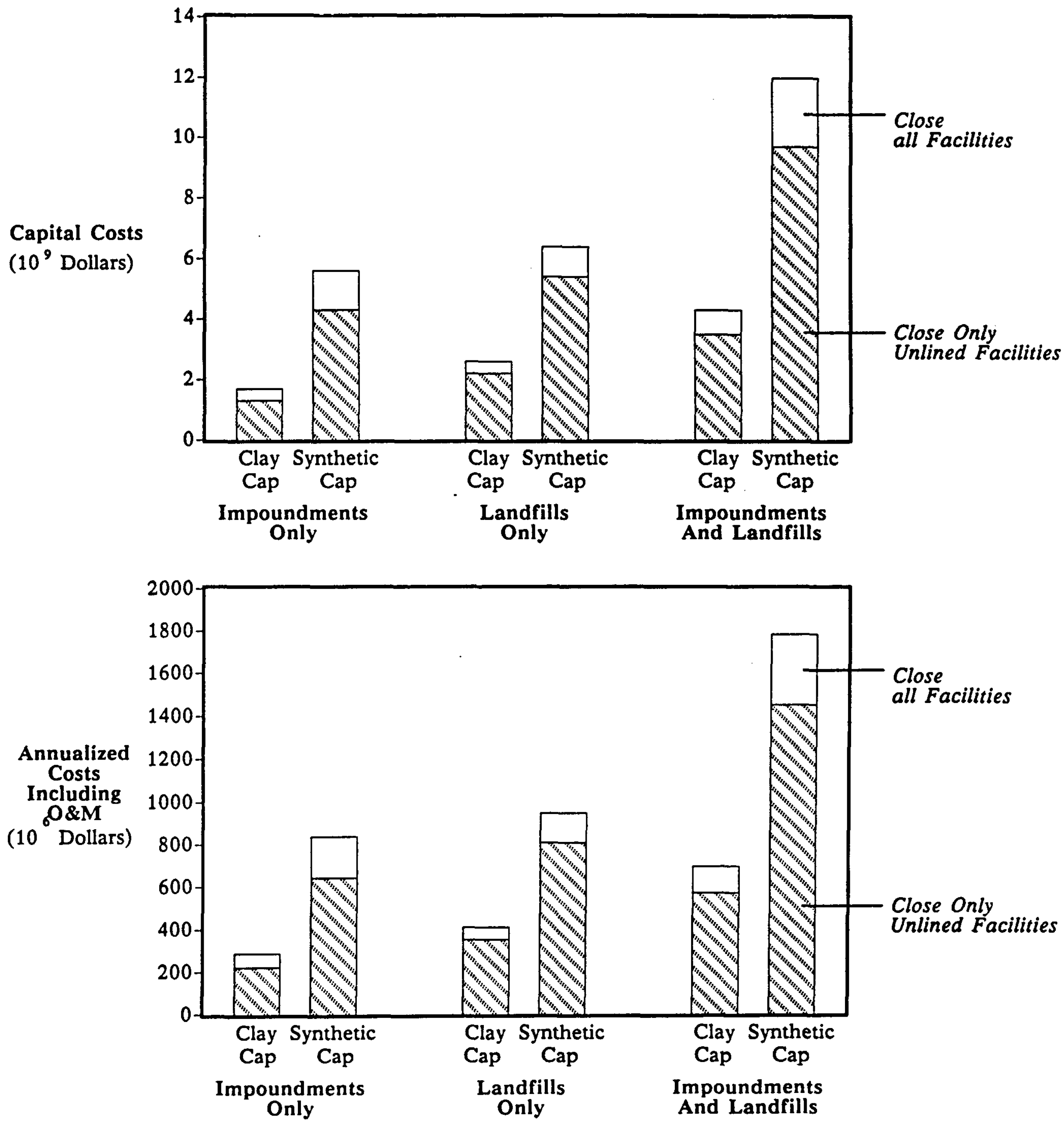
A facility that closes after the new regulations take effect, however, is subject to Subtitle C closure and post-closure requirements. The USWAG study provides an estimate of the total costs of closing all existing coal combustion waste disposal facilities and of the costs of closing only unlined facilities (See Exhibit 6-5). Total capital costs required to close all unlined landfills and impoundments would range from $3.5 billion for clay-capped facilities to $9.7 billion for synthetic-capped facilities. If all facilities closed under Subtitle C regulation, total capital costs would be about $4.3 billion for clay-capped closure and $12.0 billion for synthetic-capped closure.[29] Total annualized costs to close only unlined facilities would range from about $575 million for closure with clay caps to about $1.5 billion for synthetic caps. If all current waste management facilities were closed, annualized costs would be about $700 million for clay caps to $1.8 billion for synthetic caps.

6.2.2.5 Financial Responsibility

Subpart H of 40 CFR 264 sets forth requirements for financial responsibility for closure and post-closure care of hazardous waste facilities. A facility owner may use several different financial mechanisms to demonstrate financial responsibility, including purchasing a letter of credit, posting a surety bond, establishing a trust fund, purchasing an insurance policy, providing a corporate guarantee, or passing a financial test. Financial responsibility could be required for closure/post-closure costs or corrective action costs. The magnitude of the costs can vary considerably depending on the financial mechanism that is used and the type of activity for which financial assurance is required. For example, costs to provide a corporate guarantee or pass a financial test may be on the order of a few hundred dollars per facility; on the other hand, annual costs to obtain a letter of credit or to establish a trust fund are often based on some percentage (e.g., one to two percent) of the total

EXHIBIT 6-5

**SUMMARY OF COSTS TO CLOSE
EXISTING WASTE DISPOSAL FACILITIES**



Source: Envirosphere Company, "Report on the Costs of Utility Ash and FGD Waste Disposal," in USWAG, *Report on the Costs of Utility Ash and FGD Waste Disposal,* Appendix F Part 2, October 19, 1982.

costs of the closure/post-closure or corrective action activity to be undertaken.[30]

6.2.2.6 Design and Operating Requirements for Landfills and Surface Impoundments

The level of effort required to come into compliance with Subtitle C design and operating requirements will depend on many site-specific considerations. In some cases, it may be possible to seal off the portion of the existing disposal site that has been in use and upgrade the remaining portion by installing a liner. In other situations the required changes may be sufficiently different from existing disposal practices that the most cost-effective action may be to open an entirely new disposal facility.

Given the variety of site-specific situations that may arise, and given the regulatory flexibility EPA has in designing coal combustion waste management standards, it is not feasible to estimate how many utility waste management facilities may be affected or what type of waste management measures may be required without conducting site-specific investigations. Nevertheless, to indicate the approximate magnitude of costs that may be involved for different waste management practices, the costs for three management options -- single-lined landfills, single-lined surface impoundments, and double-lined surface impoundments -- are presented below.

Landfills

As noted earlier, single clay liners can be installed in a landfill for about $0.70 to $2.55 per ton of disposed waste and single synthetic liners for about $1.45 to $4.15 per ton of disposed waste. The costs presented in Exhibit 6-4 indicate that waste disposal costs at a representative 500 Mw power plant with no flue gas desulfurization equipment would average about $5 to $11 per ton of disposed waste for a landfill operation. Adding a single clay liner to the landfill would increase total costs to $5.70 to $13.55 per ton of disposed waste; adding a single synthetic liner would increase costs to $6.45 to $15.15 per ton of disposed waste.

These estimates appear to be similar in magnitude, although somewhat lower than costs estimated in another study of utility waste disposal costs conducted for the Utility Solid Waste Activities Group (USWAG) by Econometric Research, Inc. That study estimated that total costs for complying with requirements related to the construction, operation, and maintenance of a single-lined landfill would range from about $15 to $24 per ton of waste, depending on the type of liner.[31]

The study for USWAG also analyzed the total costs to the electric utility industry if all power plants currently using landfills were required to construct new landfills with single liners. For this scenario, USWAG assumed that existing facilities, even if lined, would have to be replaced to comply with new requirements. Total capital costs for this alternative would range from $2.6 billion for landfills with one synthetic liner to $4.0 billion for landfills with a single clay liner.[32] Estimated annualized costs were about $400 million for installing a single synthetic liner at all landfills and about $600 million for installing a single clay liner.[33]

Surface Impoundments

The costs presented in Exhibit 6-4 for unlined surface impoundments indicated that waste managed at a representative 500 Mw power plant with no FGD waste production would cost about $8 to $17 per ton of waste. Using the cost estimates for liners noted earlier (see Section 6.1.2), adding a single clay liner would increase total management costs to about $10.25-$25.20 per ton of waste, and adding a synthetic liner would increase costs to $12.70-$30.45 per ton of waste.

These cost estimates for single-lined impoundments appear to be reasonably consistent with other estimates. Studies for USWAG indicated that management costs for impoundments with a single synthetic liner were about $19 per ton of waste and $30 per ton of waste for impoundments with a single clay liner.[34]

The USWAG report also estimated the total costs to the electric utility industry to construct new impoundments with single liners (i.e., all power plants currently using surface impoundments would be required to construct new facilities to meet disposal requirements even if the current impoundment is already lined). For this alternative total capital costs would range from $5.8 billion for impoundments with single synthetic liners to $9.5 billion for impoundments with single clay liners.[35] Annualized costs would range from $850 million for single synthetic liners at all impoundments to $1.4 billion for single clay liners.[36]

The study for USWAG also estimated management costs for surface impoundments with two different types of double liners -- a double synthetic liner (each with a 30 mil thickness) and a double liner system consisting of one synthetic liner (30 mil) and a clay liner (36 inches). Total management costs for double-lined surface impoundments would range from about $29 per ton of waste for a site with two synthetic liners to $36 per ton of waste for a site with one synthetic liner and one clay liner.[37]

Industry-wide costs were also estimated for the installation of new double-lined surface impoundments at all power plants currently using surface impoundments. Total capital costs for installing a double-lined impoundment ranged from $9.3 billion for a double synthetic liner to $11.6 billion for one clay and one synthetic liner.[38] Total annualized costs were estimated at $1.4 billion for all impoundments with a double synthetic liner and $1.7 billion for all impoundments with one clay liner and one synthetic liner. A summary of the costs for the various types of lined disposal facilities discussed herein is presented in Exhibit 6-6.

6.2.2.7 Summary of Costs for Various Waste Management Alternatives

Exhibit 6-7 summarizes the costs to the electric utility industry of each of the waste management options previously discussed. The exhibit presents cost estimates for the total amount of capital required for each waste management standard and for the total amount of annualized costs (i.e., annual capital, operation, and maintenance costs) that would be incurred in order to comply with each requirement if coal-fired combustion wastes were regulated as hazardous wastes.

EXHIBIT 6-6

SUMMARY OF COSTS FOR DIFFERENT TYPES OF LINED WASTE MANAGEMENT FACILITIES

	Cost per ton	Total Annual Costs for the industry a/ (millions of dollars)
Landfills		
Basic Practice--Unlined	$ 5.00-$11.00	N.A.
Single Clay Liner	$ 5.70-$13.55	600
Single Synthetic Liner	$ 6.45-$15.15	400
Surface Impoundments		
Basic Practice--Unlined	$ 8.00-$17.00	N.A.
Single Clay Liner	$10.25-$25.20	1,380
Single Synthetic Liner	$12.70-$30.45	865
Double Synthetic Liners	$29.00	1,360
Double Liners:		
1 Synthetic and 1 Clay	$36.00	1,680

a/ Total annual costs refer to annualized costs that capture capital, operation, and maintenance expenses. Since these costs were calculated by assuming that the utility industry would have to construct new facilities to comply with hypothetical alternative regulations, these costs are in addition to the current management costs incurred by the industry.

Source: Envirosphere Company, "Report on the Costs of Utility Ash and FGD Waste Disposal." In USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 19, 1982.

Preparation of Part B Permit		
Construction of New Disposal Facilities		
Landfills		
- Single clay liner		
- Single synthetic liner	2.6	
Surface Impoundments		
- Single clay liner	9.5	1400
- Single synthetic liner	5.8	850
- Double liner		
- clay/synthetic	11.6	1700
- two synthetic	9.3	1400
Closure of Existing Disposal Facilities		
Only Unlined Facilities Close		
- Clay cap	3.5	575
- Synthetic cap	9.7	1500
All Facilities Close		
- Clay cap	4.3	700
- Synthetic cap	12.0	1800
Installation of Leachate Collection Systems	1.2	460
Provisions for Flood Protection		
Landfills	0.15	20
Impoundments	0.09	13
Ground-water Monitoring Systems	0.009-0.013	6-9
Excavate Existing Facilities, Removing Waste to Subtitle C Facilities	1028.0 a/	NA

a/ Costs shown are for capital, operation, and maintenance costs for the entire industry since the amount of capital required was not readily available.

A combination of compliance alternatives could occur (e.g., closing existing disposal facilities and constructing new facilities with leachate collection and ground-water monitoring systems). The actual cost to the electric utility industry for complying with RCRA Subtitle C requirements would depend on the regulatory actions taken by the Agency if the temporary exemption under Section 3001 of RCRA is removed. Three possible regulatory scenarios are discussed in the following section.

6.2.3 Potential Costs to the Industry of RCRA Subtitle C Waste Management

Section 6.2.2 presented cost estimates for individual regulatory requirements that could be imposed on utilities if EPA determines that Subtitle C regulation is warranted for coal combustion wastes. In this section, three possible regulatory scenarios are examined to quantify the range of incremental costs that could result from various regulatory options. In the first scenario, the incremental costs of regulating a portion of low volume wastes under Subtitle C are presented. The second scenario assumes that all coal combustion waste would be subject to Subtitle C requirements. The third scenario assumes that high volume coal combustion wastes would be tested for RCRA hazardous characteristics and that a small portion of the waste would be classified as Subtitle C characteristic waste. For all three regulatory scenarios, costs are shown only for bringing all existing power plants into compliance with the assumed RCRA Subtitle C management regulations.

Low Volume Waste Scenario

This scenario evaluates the costs to the utility industry if some low volume waste streams are classified as hazardous wastes under Subtitle C. As discussed in Chapter Three, some of these wastes can exhibit hazardous characteristics such as corrosivity. The information available to EPA at this time does not permit the Agency to quantify the amount of low volume wastes that may exhibit hazardous characteristics. In this scenario, EPA has assumed that all water-side boiler cleaning wastes are regulated as hazardous wastes since these waste streams may exhibit corrosive characteristics. These waste streams are assumed to be hazardous to provide an approximate estimate of the costs to the industry if some low volume wastes display RCRA hazardous characteristics. That is, both high-volume and low-volume wastes could be tested for RCRA hazardous characteristics, but only a small portion of the low-volume wastes (as represented by all water-side boiler cleaning wastes) would need to be treated as hazardous.

As shown in Exhibit 3-19, a representative power plant generates about 180,000 gallons per year of water-side boiler cleaning wastes. The cost to dispose of these wastes as hazardous liquids can vary depending on waste stream variability, regional differences in disposal costs, and quantity to be disposed, among other factors.[39] For purposes of this analysis, an incremental cost of $2 per gallon (including transportation) has been assumed based on a 1985 survey of hazardous waste management prices.[40] With 180,000 gallons generated per year at a representative power plant, annual disposal costs would be about $360,000 per power plant. Since there are 514 power plants in the U.S., annual disposal costs to the utility industry would be about $185 million.

Full Subtitle C Regulation Scenario

If EPA lists high volume coal combustion waste streams in 40 CFR 261.31-261.33, all utilities will be affected. Utilities would be required to manage all coal combustion wastes in Subtitle C permitted facilities. To estimate the incremental costs to the industry of this regulatory scenario, the Agency assumed that all utilities would close existing facilities and open new waste management facilities that complied with Subtitle C standards. This scenario assumes that the costs of managing wastes off-site will equal the costs of managing wastes on-site and that existing facilities would be closed in the six months before Subtitle C regulation took effect, thereby avoiding Subtitle C closure and post-closure requirements.

Under existing state regulations, a clay cap is assumed to be adequate to close existing waste management facilities. The total annual costs of closing all existing facilities with a clay cap would be $700 million. For the new facilities, EPA assumed utilities would prepare a Part B permit application, construct new landfills and surface impoundments with clay/synthetic double liners, install leachate collection systems, make provisions for flood protection, and install ground-water monitoring systems. To determine incremental costs for the industry, EPA assumed that the current proportions of waste management facilities that were landfills and surface impoundments would remain unchanged under Subtitle C regulation. As summarized in Exhibit 6-7, total annual costs of the new Subtitle C facilities would be $54 million for Part B permit applications, $725 million for new double lined landfills,[41] $1700 million for new double lined surface impoundments, $460 million for leachate collection systems, $33 million for flood protection, and $9 million for ground-water monitoring. Total incremental costs for this regulatory scenario would be $3.7 billion annually.[42]

High Volume Characteristic Waste Scenario

If coal combustion wastes were not exempt from RCRA Subtitle C regulation, utilities would have to test high-volume and low-volume coal combustion wastes for RCRA hazardous characteristics. Based on the RCRA characteristic results in Chapter Five, it appears that only a small portion of coal combustion wastes possess the hazardous characteristics of EP Toxicity or corrosivity. For purposes of this scenario, the Agency assumed that five percent of the wastes generated by utilities would need to be disposed in Subtitle C permitted facilities. The Agency does not have sufficient information to know exactly the amount of coal combustion waste that would exhibit RCRA hazardous characteristics. EPA believes that coal combustion wastes generally would not fail the RCRA hazardous characteristic tests. Based on limited information presented in Chapter Five that indicate about five percent of all ground-water observations at utility sites exceed the Primary Drinking Water Standards, the Agency assumed that five percent of all wastes would require Subtitle C treatment. The total annual cost to the industry if utilities close existing facilities and construct new double lined facilities for five percent of all coal combustion wastes would be $185 million.

6.3 IMPACT OF REGULATORY ALTERNATIVES ON UTILIZATION OF COAL COMBUSTION WASTES

As discussed in Chapter Four, coal-fired utility wastes have been used in a variety of applications by electric utilities and other industries to replace other types of material. The use of utility wastes as a replacement for other materials has reduced the amount of wastes utilities have had to dispose, while correspondingly reducing the resource requirements of other industries that have managed to find a productive use for the waste material.

In the event that some or all of these wastes were declared hazardous, it is possible that the amount of by-product utilization of coal-fired utility wastes would decline as a result of increased costs for their use and the potential for outright prohibition of their use in some applications. On the other hand, it is possible that certain forms of utilization (e.g., the use of fly ash in cement) may be deemed environmentally acceptable practices if the wastes would be unlikely to pose an environmental threat when used for such purposes. Since costs for other forms of disposal may increase, utilization may also increase. However, for discussion purposes, this section assumes that designation as a hazardous waste would tend to discourage by-product utilization.

The costs that would be incurred as a result of environmental concerns over the utilization of coal-fired utility wastes would depend on the regulatory requirements that would have to be followed to use the wastes. The more stringent the additional regulatory burden imposed, the greater the impact on by-product utilization due to the higher costs of using the wastes.

In the USWAG study referenced above, the potential range of costs associated with reduced use of coal combustion by-products was also evaluated. Three different regulatory scenarios were analyzed.[43]

- The transportation of coal-fired utility wastes is regulated as hazardous waste transportation under Subtitle C of RCRA; use or disposal of the wastes would not be regulated.
- All activities associated with reuse of coal combustion by-products is regulated, and the regulations affect both the transporter and owner/operator of a Subtitle C hazardous waste management facility.
- Reuse of coal combustion by-products is prohibited.

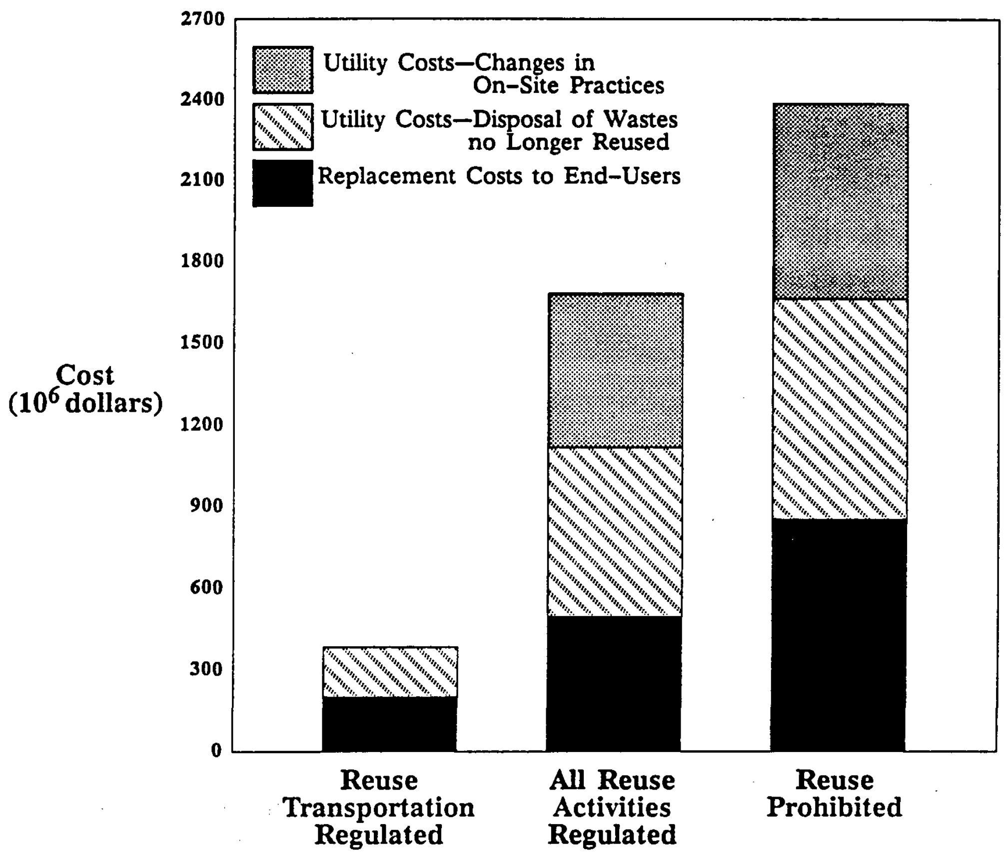
There would be three types of costs incurred under these regulatory scenarios: (1) replacement costs to the end-users who would no longer find it economic to utilize the coal combustion by-products, (2) costs to utilities to dispose of wastes no longer reused by other industries, and (3) additional costs to the utility industry for replacement and disposal of wastes that could no longer be used on-site. A summary of the costs associated with each scenario is provided in Exhibit 6-8.[44]

If the transportation of coal combustion by-products were subject to increased regulation under Subtitle C, the USWAG report estimated that the use of these by-products would decline by nearly 40 percent, increasing overall disposal volumes by about 8 percent.[45] The industries that would be affected the most would be the roofing granules industry (conventional roofing granules would replace bottom ash and boiler slag at a cost of about $115 million in annual costs) and the concrete industry (portland cement would replace fly ash at a cost of about $40 million in annual costs).[46]

If all activities pertaining to reuse of coal combustion wastes were subject to Subtitle C regulations, utilization of coal combustion

EXHIBIT 6-8

Summary of Economic Impacts on By-Product Utilization under Different RCRA Regulatory Scenarios*



*All costs are annualized based on impacts estimated from 1984–2000.

Source: USWAG, *Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products*, Appendix G, October 26, 1982 by-products was estimated to decline by about 75 percent, increasing overall disposal volumes by about 14 percent.[47] The greatest impact would be on the concrete industry, which would spend about $270 million annually to replace fly ash with portland cement.[48]

If all reuse of coal combustion by-products were prohibited, industries using these by-products would have to find suitable replacements; total disposal volumes would increase by nearly 20 percent.[49] The largest impacts would be on the asphalt industry, which would be forced to replace ash with asphalt at a cost of approximately $250 million annually, and the concrete industry, which would replace fly ash with portland cement at a cost of about $270 million annually.[50]

6.4 ECONOMIC IMPACTS OF ALTERNATIVE WASTE DISPOSAL OPTIONS

Since many alternative disposal practices discussed in this chapter could impose additional costs on the electric utility industry, this section evaluates the effect that these increased costs might have on electricity generation costs and U.S. coal consumption. This study employs three measures to determine the potential economic impact of alternative disposal practices:

1. Average increase in electricity generation costs at existing coal-fired power plants,

2. Average increase in electricity generation costs at coal-fired power plants yet to be constructed, and

3. Impact on the electric utility industry's consumption of coal.

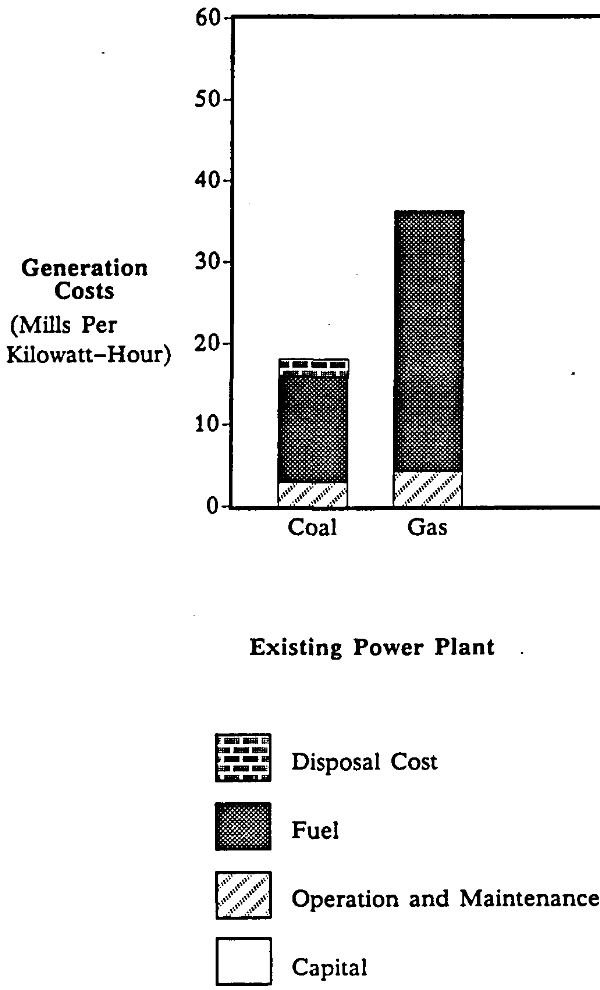
Exhibit 6-9 summarizes the cost of generating electricity at both existing and yet-to-be-constructed power plants (see Appendix G for a detailed discussion of the assumptions used to determine these generation costs).[51] Disposal costs average about 3-5 percent of total generation costs at existing coal-fired power plants, but only about 1-3 percent at future power plants. Although the actual costs of disposal at existing and future power plants are similar, the percentages are different because total generation costs at future power plants are higher than generation costs at existing power plants (resulting in a lower overall percentage for disposal costs at future power plants). Total generation costs are higher at future power plants because they include capital, operation and maintenance, and fuel costs, while the generation costs for existing power plants include operation and maintenance and fuel costs only.[52]
Based on the cost assumptions used to develop Exhibit 6-9, coal-fired electricity generation at both new and future baseload[53] power plants is less expensive than generation with natural gas.[54]

The economic impacts likely to result from the use of alternative coal-fired utility waste disposal practices will depend upon several factors, including which disposal options are required, how much the cost of coal-fired electricity generation changes, and whether these changes affect the relative competitiveness between coal and other fuels. To indicate the potential magnitude of these impacts, Exhibit 6-10 summarizes the potential cost impacts on electricity generation rates due to the alternative waste disposal options discussed earlier in this chapter.

As indicated in Exhibit 6-10, some alternative disposal options could

EXHIBIT 6-9

IMPACT OF CURRENT WASTE DISPOSAL COSTS ON TOTAL ELECTRICITY GENERATION COSTS*



* Generation costs are based on typical 500 Mw power plant in the midwest operating at 70 percent utilization rate. Regional costs will vary depending on fuel price and availability, among other factors.

Source: Generation cost estimates are from ICF Incorporated. Waste disposal costs are taken from Arthur D. Little, Inc., *Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants*. June 1985.

EXHIBIT 6-10

IMPACT OF ALTERNATIVE DISPOSAL OPTIONS ON ELECTRICITY GENERATION COSTS

Option	Incremental Cost ($/ton of disposed waste)	Impact On Generation Costs: mills/kilowatt-hour a/	Impact On Generation Costs: % of Total Generation Costs, Existing Plant	Impact On Generation Costs: % of Total Generation Costs, Future Plant
Part B Permit	$0.55	0.03	0.2	0.1
Existing Landfills b/				
Single Clay Liner	$0.70-$2.55	0.04-0.16	0.2-0.9	0.1-0.3
Single Synthetic Liner	$1.45-$4.15	0.09-0.26	0.5-1.4	0.2-0.6
Existing Surface Impoundments				
Single Clay Liner	$2.25-$8.20	0.14-0.51	0.8-2.8	0.3-1.1
Single Synthetic Liner	$4.70-$13.45	0.30-0.84	1.7-4.7	0.6-1.8
New Landfills				
Single Clay Liner	$ 5.70-$12.55	0.36-0.79	2.0-4.4	0.8-1.7
Single Synthetic Liner	$ 6.45-$15.15	0.40-0.95	2.2-5.3	0.9-2.0
New Surface Impoundments				
Single Clay Liner	$10.25-$25.20	0.64-1.58	3.6-8.8	1.4-3.4
Single Synthetic Liner	$12.70-$30.45	0.80-1.91	4.4-10.6	1.7-4.1
Double Synthetic Liner	$29.00	1.82	10.1	3.9
Double Synthetic/ Clay Liner	$36.00	2.26	12.6	4.8
Site Closure	$2.10-$14.75	0.13-0.93	0.7-5.2	0.3-2.0
Leachate Control	$4.70	0.30	1.7	0.6
Flood Protection	$0.25-$0.55	0.02-0.03	0.1-0.2	c/
Ground-water Monitoring	$0.06-$0.10	0.004-0.006	c/	c/
Utilization				
Transportation				
Regulated	$3.00	0.19	1.1	0.4
All Activities				
Regulated	$13.20	0.83	4.6	1.8
Reuse Prohibited	$18.75	1.18	6.6	2.5

a/ Based on a representative 500 Mw plant operating at a 70 percent utilization rate. Costs are incremental costs only; that is, cost impact of new disposal facilities is only that portion of costs in excess of current disposal costs (see Exhibit 6-4 for these costs). A mill is one-tenth of a cent ($0.001).

b/ Costs for existing waste disposal facilities refer only to the cost of liner installation. Costs for new waste disposal facilities refer to all the costs for site construction and liner installation.

c/ Less than 0.1 percent.

increase electricity generation costs at existing power plants by several percent. In some cases the cost impact could be substantial if several options were combined as part of an integrated waste management strategy. For example, if new waste management regulations led to closure of the current disposal site and the construction of a new lined facility with a leachate control system, flood protection, and ground-water monitoring system, coal-fired generation costs at existing coal-fired power plants could increase by nearly 20 percent (roughly 3.5 mills/kilowatt-hour).

Generation cost increases of this magnitude have the potential to reduce coal consumption at existing coal-fired power plants if these cost increases make it more expensive to generate electricity with coal than with other fuels. A utility decides how much electricity to generate at any existing power plant primarily by comparing the operation and maintenance costs (including fuel) associated with generating electricity at all of its power plants. Power plants with the lowest generation costs will be operated first. Generally, it is less expensive to generate electricity with coal than with other fuels such as oil or gas, but oil-fired electricity generation can be competitive with coal when the price of oil is approximately $10-$15 per barrel.[55] However, whether and to what degree electric utilities would shift away from the use of coal would depend on several factors, including the relative price of coal compared with the price of other fuels, the magnitude of the increase in generation costs if disposal practices were altered, and the overall efficiency of competing power plants.

For power plants yet to be constructed, the impact of higher disposal costs on coal consumption could be more substantial, with possible generation cost increases approaching 8-10 percent if several options are combined. Generation cost increases of this magnitude could have a substantial effect on the amount of coal consumed at future power plants since many utilities may decide not to build coal-fired power plants. Although currently coal-fired electricity generation may be a more economic option than oil-fired or gas-fired generation at plants yet to be constructed, this situation could change if more expensive disposal practices were required for coal combustion wastes. This is because the higher capital costs of coal-fired electricity generation, compared with oil- or gas-fired generation, reduces the overall cost differential between the use of coal and the use of oil or gas at future power plants (compared to the cost differential between coal and oil or gas at existing power plants). As a result, coal is more likely to be replaced by alternative fuels at future power plants than it is at existing power plants.

In fact, since oil prices dropped below $20 per barrel in early 1986, many utilities have been seriously evaluating the feasibility of building oil- or gas-fired generating capacity in lieu of coal-fired units. As a result, in some instances even an increase of a few percent in coal-fired generation costs could be sufficient to tip the balance in favor of using natural gas or oil to fuel power plants that have not yet been constructed. If increased disposal costs do promote such competition, growth in future U.S. consumption of coal would probably decline. The exact magnitude of this decrease in future coal consumption would depend on many factors, including the type of new waste disposal practices adopted and the price of alternative fuels in different regions of the country. An in-depth analysis of the potential impact of alternative waste management scenarios on electric utility generation practices and investment decisions and, as a result, the level of coal consumption, is beyond the scope of this Report to Congress. However, EPA intends to seek more information and analysis on the issue of economic impacts through the public hearing process and through its own additional investigations. As required by law EPA will conduct the appropriate regulatory impact analyses, including the economic impact analysis, during the six month public review period following submission of this report to Congress if it is determined that current utility waste management practices for coal-fired combustion wastes are inadequate and additional regulations are warranted.

6.5 SUMMARY

The cost to manage coal combustion waste in basic waste management facilities currently ranges from as little as $2 to as much as $31 per ton. The wide range in management costs is primarily due to differences in (1) the type of facility, (2) the size of the facility and (3) the characteristics of the waste.

- Some facilities currently incur additional costs because they have undertaken additional safeguards against leaching, including liner installation, leachate collection and treatment, and ground-water monitoring.
- Management costs at surface impoundments tend to be greater than those at landfills because of the higher costs of site preparation at impoundments.
- The size of larger waste disposal facilities allows them to operate more efficiently, which tends to reduce the cost per ton of waste management.
- Fly ash is typically more expensive to manage than bottom ash or FGD waste because of additional requirements for collection, handling, and treatment prior to disposal.

- If additional regulations are promulgated requiring electric utilities to alter the current methods by which they manage coal-fired wastes, additional costs may be incurred by the industry as it complies with the new requirements.

- The most common practice for controlling leaching at a waste management site is installation of a liner prior to placement of the waste. Liners are usually made of low permeable clay or a synthetic material and can be installed in one or more layers. The cost of installing a liner ranges from $0.70 to $8.20 per ton of waste for clay liners and $1.45 to $13.45 per ton for synthetic liners. Total disposal costs for single-lined landfills range from about $6 to $15 per ton of waste, while costs for single-lined surface impoundments range from $10 to $30 per ton. Industry-wide costs to construct and install lined management facilities could range from $0.4 to $1.7 billion on an annualized basis, depending on type of facility, type of liner material, and number of liners installed.

- Installation of leachate collection systems to control potential environmental problems that might result from substances leaching from a waste management site could cost about $4 to $5 per ton of waste. Total costs to the utility industry to install leachate collection systems could be $1.2 billion in capital costs, or about $460 million in annualized costs.

- The cost of installing a ground-water monitoring system to detect the presence and concentration of various waste constituents in the ground water surrounding a waste management facility is generally less than $0.25 per ton of waste. Total capital requirements to the industry would likely range from $9 to $13 million, with annual costs of $6 to $9 million.

- If coal combustion wastes were regulated under Subtitle C of RCRA, costs to the utility industry could approach $3.7 billion annually if all wastes were listed as hazardous. Costs would be substantially lower than $3.7 billion annually if coal combustion wastes were tested for hazardous characteristics since only a small portion of coal combustion wastes would be likely to fail the RCRA hazardous characteristic tests. These costs to comply with Subtitle C do not include corrective action costs or the higher costs that may be associated with recycling coal combustion wastes; these costs to the utility industry could be very high.

- New waste management practices could increase the cost of generating electricity at existing coal-fired power plants by nearly 20 percent in some cases. Although coal is generally the preferred boiler fuel at existing power plants, an increase of this magnitude could cause a decline in the amount of coal consumed at these power plants if alternative fuel prices were reasonably competitive.

- If new management practices are required at future power plants, the increase in generation costs is unlikely to exceed 10 percent. Although on a percentage basis this increase would be less than the percentage increase possible at existing power plants, the choice of fuels at future power plants is much more competitive (due to the capital costs that must be included in the costs of a future power plant). In some instances this could lead to a decrease in coal consumption if the use of alternative fuels is found to be more cost effective since many utilities may decide not to build coal-fired power plants.

[7] In one study, the cost of building and operating an artificial reef construction system was estimated to be about $50 per ton, roughly double the amount estimated by the study authors for more conventional waste disposal. In those situations where space constraints or other factors would substantially increase the costs for conventional disposal, ocean disposal through reef construction was seen as an economically viable option. See J.H. Parker, P.M.J. Woodhead, and I.W. Dued all, "A Constructive Disposal Option for Coal Wastes -- Artificial Reefs," in Proceedings of the Second Conference on Management of Municipal, Hazardous, and Coal Wastes, S. Sengupta (Ed.), September 1984, p. 134.

[8] Arthur D. Little, p. 6-132. "Installed cost" of a liner (expressed in terms of cost per ton of disposed waste) refers to the increase in the cost of disposing of one ton of waste as a result of adding a liner to an unlined landfill or surface impoundment.

[9] Ibid. The costs in the Arthur D. Little report were presented for an 18-inch clay liner. Costs were doubled to approximate the costs for installing a 36-inch clay liner, which is currently a more common practice. The dollar per ton estimate was derived by multiplying total capital costs by a 14.5 percent capital recovery factor to determine annual capital charges. Assuming that a 500 Mw power plant has a 45 acre landfill disposal site, total capital charges would range from $945,000 to $3.4 million, or about $140,000 to $490,000 in annualized charges. Assuming that a 500 Mw power plant would need a 145-acre wet surface impoundment, total costs would range from $3.0 to $10.9 million, or $440,000 to $1.6 million in annualized costs. These annualized charges were then divided by the amount of waste produced annually by a 500 Mw power plant with no FGD process, (i.e., 192,500 tons) to determine the dollar per ton cost. This approach is used throughout the report to calculate dollar per ton estimates. See Appendix G for more detail on this methodology.

[10] Ibid. For landfills, total installed costs would range from $1.9 to $5.1 million per plant, assuming a 45-acre disposal site. Annual costs would range from about $280,000 to $740,000. Based on 192,500 tons of waste, the cost is $1.45-$3.85 per ton. For ponds (i.e., impoundments), total installed costs would be $6.2-$16.4 million, or $900,000-$2.4 million annualized. On a dollar per ton basis, this range is $4.70-$12.35.

[11] Ibid. For landfills total installed costs would range from $2.7-$5.5 million, or about $385,000-$800,000 in annual costs per ton. This corresponds to $2.00-$4.15 per ton. Total installed costs for ponding operations are $8.6-$17.8 million, or $1.2-$2.6 million annualized. This corresponds to $6.45-$13.45 per ton.

[12] Ibid.

[13] Total capital costs for landfills of $3.0 to $5.0 million correspond to annual charges of about $430,000 to $720,000. Assuming 192,500 tons of waste, the per ton cost is $2.25 to $3.75. Using the same approach to derive disposal costs at a 145-acre lined impoundment yields $7.20 to $12.00 per ton.

[14] A waste management unit is not subject to regulation under Section 264.1 if the Regional Administrator finds that the unit (1) is an engineered structure, (2) does not receive or contain liquid waste or waste containing free liquids, (3) was designed and is operated in such a way to exclude liquids, precipitation, and other run-on and run-off (4) has both inner and outer layers of containment enclosing the waste, (5) has a leak detection system built into each containment layer, (6) will have continuing operation and maintenance of these leak detection systems during its active life and throughout the closure and post-closure care periods, and (7) is constructed in such a way that, to a reasonable degree of certainty, hazardous constituents will not migrate beyond the outer containment layer prior to the end of the post-closure care period. (40 CFR 264.90(b)(vii).

[15] See 40 CFR 246.143.

[16] These specified wastes are liquid hazardous wastes that have a pH less than or equal to 2.0 and/or (1) free cyanides at concentrations greater than or equal to 1,000 mg/l, (2) arsenic and/or arsenical compounds at concentrations greater than or equal to 500 mg/l, (3) cadmium and/or cadmium compounds at concentrations greater than or equal to 100 mg/l, (4) chromium and/or chromium compounds at concentrations greater than or equal to 500 mg/l (5) lead and/or lead compounds at concentrations greater than or equal to 500 mg/l, (6) nickel and/or nickel compounds at concentrations greater than or equal to 134 mg/l, (7) mercury and/or mercury compounds at concentrations greater than or equal to 20 mg/l, (8) selenium and/or selenium compounds at concentrations greater than or equal to 100 mg/l, (9) thallium and/or thallium compounds at concentrations greater than or equal to 130 mg/l, (10) polychlorinated biphenyls at concentrations greater than or equal to 50 mg/l, (11) halogenated organic compounds at concentrations greater than or equal to 1,000 mg/kg.

[17] Envirosphere Company, "Report on the Costs of Utility Ash and FGD Waste Disposal", in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 19, 1982, p. 21, Appendix F, part 2. Dollar per ton estimates were determined by calculating annual costs ($721,000 x 14.5 percent capital recovery factor = $104,500). The capital recovery factor was applied to all costs since a breakdown of different types of costs required for a Part B permit was not available.

[18] Ibid, p. 18.

[19] Assuming a 145-acre impoundment site, costs would be about $107,000. On a per ton basis, this corresponds to about $0.55. For a 45-acre landfill with costs of $1100 per acre, total costs would be about $50,000, for a per ton cost of $0.25.

[20] Envirosphere, in USWAG, Appendix F, Part 2, p. 27, 32.

[21] Arthur D. Little, p. 6-133. On an annualized basis, capital costs would range from about $2,650 to $3,550.

22 Envirosphere Company, in USWAG, Appendix F, Part 2, p. 37. Envirosphere estimated that about four wells, one upgradient from the site and three downgradient, would be required for each 100 acre disposal site (or about six wells for a site of 145 acres) at a capital cost of approximately $6,000 per well. Total capital costs for six wells would be $36,000, which is about $5,200 on an annualized basis. It was assumed that the wells would be sampled quarterly the first year, then semi-annually thereafter. The operation and maintenance costs would average about $2,500 to $3,000 per well, for facility costs (assuming six wells) of $15,000 to $18,000 per year. Total annualized costs, therefore, would range from $20,200 to $23,200, or $0.10 to $0.12 per ton of waste disposed.

23 For a more complete discussion, see ICF Incorporated, Liner Location Risk and Cost Analysis Model, Draft Phase II Report, Appendix F-2, Office of Solid Waste, U.S. Environmental Protection Agency, March 1987.

24 The cost equation on which this cost estimate is based was developed for typical RCRA Subtitle C landfills. Since these facilities tend to be much smaller than the size of utility disposal areas, extrapolating the cost equation for larger sizes may introduce some errors. Nevertheless, these cost estimates do indicate the approximate magnitude of corrective action costs that would likely be incurred.

25 Econometric Research, "The Economic Costs of Potential RCRA Regulations Applied to Existing Coal-Fired Electric Utility Boilers," in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, p. 15, Appendix F, part 1.

26 Ibid, p. 15.

27 Ibid, p. 18. On a per acre basis, total annual costs range from $6,700 to $19,600 for surface impoundments and $9,000 to $21,000 for landfills. For a 145-acre impoundment, this corresponds to $1.0 to $2.8 million in total annual costs, or $5.00 to $14.75 per ton of waste. For landfills the per ton cost would be $2.10 to $4.90 based on total annual costs of $0.4 to $0.9 million.

28 See Administrative Procedure Act, U.S. Code 5 Sec. part 551.

29 Ibid, see pages 26 and 31 of the Econometric report for all closure costs.

30 For further discussion of the potential magnitude of these costs, see ICF Incorporated, Flexible Regulatory and Enforcement Policies for Corrective Action, prepared for U.S. Environmental Protection Agency, September 12, 1985.

31 Econometric Research, in USWAG, Appendix F, Part 1, p. 15. Econometric Research used capital costs for disposal of about $5.20 per ton of waste produced over a 20-year life of the facility for synthetic liners and about $8.10 per ton for clay liners, plus about $0.06 per ton per year for operation and maintenance costs. Total initial capital outlays would then be $104 per ton ($5.20 per ton times 20 years) for synthetic liners, or about $15.08 per ton on an annualized basis, and $162 per ton ($8.10 per ton times 20 years) for clay liners, or $23.49 per ton on an annualized basis. With the addition of

the $0.06 per ton for operation and maintenance costs, total costs would range from $15.14 per ton for synthetic liners and $23.55 per ton for clay liners for each ton of waste produced annually.

32 Ibid., p. 27. Total capital costs for existing power plants were assumed to be $2.1 billion for single synthetic liners and $3.2 billion for single clay liners. Since these cost estimates were based on a universe of 412 power plants, costs were adjusted upward by 514/412 to approximate total industry costs for the number of power plants estimated at the time of this study -- 514 power plants. This adjustment was made for all industry-wide costs cited from the USWAG report.

33 Ibid., p. 32.

34 Ibid., p. 18. Econometric Research, Inc., calculated that disposal costs for an impoundment with a single synthetic liner were about $0.95 per ton of waste over the life of the facility and about $1.50 per ton of waste for clay-lined impoundments. For a plant generating 192,500 tons each year for 20 years (or 3.85 million tons), that corresponds to 3.85 million tons x $0.95 per ton = $3.7 million for an impoundment with a single synthetic liner (or about $19 per ton based on $3.7 million divided by 192,500 tons of waste annually) and 3.85 million tons x $1.50 per ton = $5.8 million for an impoundment with a single clay liner (or about $30 for each ton of waste disposed in a year).

35 Ibid, p. 26. The costs in the USWAG report were adjusted by 514/412 to account for the 514 power plants estimated at the time of this study compared to the 412 power plants assumed in the USWAG report.

36 Ibid. p. 31.

37 Ibid, p. 18. The double synthetic liner disposal system averages about $1.45 per ton over the life of the facility and a system with one synthetic liner and one clay liner costs about $1.80 per ton. At 3.85 million tons of waste over a 20 year facility life, that is $5.6 million for a double synthetic liner (or about $29 for each ton disposed in a year). For a combination synthetic/clay liner system, 3.85 million tons x $1.80 per ton = $6.9 million (or about $36 per ton).

38 Ibid, p. 26.

39 ICF Incorporated, 1985 Survey of Selected Firms In The Commercial Hazardous Waste Management Industry, Prepared for U.S. Environmental Protection Agency, November 6, 1986.

40 Ibid.

41 To develop a cost estimate for landfills constructed with clay/synthetic double liners, the ratio of the cost of single clay and synthetic liners at landfills in Exhibit 6-7 to the cost of single clay and synthetic liners at surface impoundments was multiplied by the cost of clay/synthetic liners at surface impoundments.

42 The costs to close and cap existing facilities have been included in this estimate, while corrective action costs have not been included. Although closure costs will be incurred eventually by the industry, in most cases they would not be incurred for many years to come. To be conservative, EPA has included closure costs as part of potential RCRA Subtitle C compliance costs.

43 Envirosphere Company, "Economic Analysis of Impact of RCRA On Coal Combustion By-Products Utilization." In USWAG, Report and Technical Studies On the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix G.

44 Envirosphere Company, in USWAG, Appendix G. The costs in Exhibit 6-8 are based on estimated impacts between 1984 and 2000 and adjusted by a capital recovery factor of 14.5 percent to annualize the costs (total capital requirements were not identified). It was estimated that about 203 million tons of coal combustion by-products would be used over this period, with a similar amount used on-site by the utilities. That is, the costs assume that the amount of by-products utilized would have increased over time.

45 Ibid., p. 89. Total ash generation in 2000 was assumed to be 169.5 million tons, with about 27.3 million tons utilized and therefore, 142.2 million tons destined for disposal areas. Utilization was estimated to decline about 11.5 million tons, so the total amount of waste to be disposed would increase to 153.7 million tons.

46 Ibid.

47 Ibid., p. 91. Total utilization was assumed to decline by about 20.3 million tons in 2000. Therefore, the total amount of waste disposed would increase from 142.2 million tons to 162.5 million tons.

48 Ibid.

49 Total utilization was assumed to be 27.3 million tons in 2000, thereby increasing total disposal volume from 142.2 million tons to 169.5 million tons.

50 Envirosphere Company, in USWAG, Appendix G, p. 93.

51 To estimate the potential impact of alternative disposal practices on electricity generation costs, the first step was to calculate the approximate portion of generation costs due to current basic disposal practices. Current basic disposal practices for coal-fired utility wastes were assumed to be disposal in either an unlined pond or landfill, although other practices are sometimes followed. Generation costs for a typical coal- and gas-fired power plant are shown to indicate the relative competitiveness of these two fuels when current disposal practices for coal-fired utility wastes are followed. See Appendix G for a detailed discussion of the assumptions used to determine these generation costs.

52 Capital costs are not included in the cost estimates for existing power plants because these are "sunk" costs, i.e., they have already been spent. As a result, the percentage impact on total generation costs at existing power plants is larger because the cost base is smaller compared to future power plants.

53 Baseload refers to power plants that are operated as much as possible to maximize the amount of electricity these plants can generate. For this analysis a baseload power plant is assumed to operate 70 percent of the time.

54 The generation costs in Exhibit 6-9 are intended to be representative of typical power plants. However, the actual cost of generation and the relative competitiveness between coal and gas depends on many factors, including plant size, utilization rate, and delivered fuel cost.

55 This price range is only intended to illustrate the approximate range at which oil becomes competitive with coal at existing power plants. The actual level at which coal might begin to lose market share depends on many factors, including relative price differentials, fuel availability, gas prices vis-a-vis oil prices, types of power plants (i.e., overall plant efficiency), etc.

CHAPTER SEVEN

CONCLUSIONS AND RECOMMENDATIONS

This chapter concludes the Environmental Protection Agency's Report to Congress on fossil fuel combustion wastes. Pursuant to the requirements of Section 8002(n) of the Resource Conservation and Recovery Act (RCRA), the Report addresses the nature and volumes of coal combustion wastes, the environmental and human health effects of the disposal of coal combustion wastes, present disposal and utilization practices, and the costs and economic impacts of employing alternative disposal and utilization techniques. A statement of the scope of the report and a summary of the report's findings are presented below, followed by the Agency's recommendations.

7.1 SCOPE OF REPORT

As discussed in Chapter One, this Report to Congress covers the generation of coal-fired combustion wastes by the electric utility industry. Other fossil fuel combustion wastes not discussed in this report include coal, oil and gas combustion wastes from other industries and oil and gas combustion wastes from electric utilities. Overall, coal combustion by electric utilities accounts for approximately 90 percent of all fossil fuel combustion wastes that are produced. Moreover, this percentage is likely to increase in the future since coal consumption by the electric utility industry is expected to increase substantially while coal use by other sectors remains relatively constant. Electric utility coal consumption will grow as new coal-fired power plants are constructed to meet increasing electricity requirements in the United States.

7.2 SUMMARY OF REPORT

The Agency's conclusions from the information presented in this report are summarized under seven major groupings paralleling the organization of the report: 1) Location and Characteristics of Coal-Fired Power Plants, 2) Waste Quantities and Characteristics, 3) Waste Management Practices, 4) Potential Hazardous Characteristics, 5) Evidence of Environmental Transport of Potentially Hazardous Constituents, 6) Evidence of Damage, and 7) Potential Costs of Regulation.

7.2.1 Location and Characteristics of Coal-Fired Power Plants

1. <u>There are about 500 power plant sites in the United States that consume coal to generate electricity</u>. Each power plant may be the location for more than one generating unit; at these 500 power plants there are nearly 1400 generating units.

2. <u>The size of coal-fired power plants can vary greatly</u>. The size of a power plant is typically measured by the number of megawatts (Mw) of generating capacity. Coal-fired power plants can range in size from less than 50 Mw to larger than 3000 Mw.

3. Coal-fired power plants are located throughout the United States. Coal is used to generate electricity in every EPA region; almost every state has some coal-fired generating capacity.

4. More coal-fired power plants will be built as the demand for electricity increases. Coal is a fuel often used by the electric utility industry to generate power. This reliance on coal is unlikely to change for many years to come in the absence of greatly increased costs for coal-fired electricity.

5. Coal-fired power plants are located in areas of widely-varying population density. Some power plants are located in remote rural areas, whereas others are located in urban environments. They are usually, although not always, located at least a couple of kilometers from major population concentrations. In general they are located near a major body of surface water such as a lake, river, or stream.

7.2.2. Waste Quantities and Characteristics

1. The amount of wastes generated annually by coal-fired power plants is large by any standard. About 84 million tons of high-volume wastes -- fly ash, bottom ash, boiler slag, and FGD sludge -- are generated annually. The total amount of low-volume wastes generated from equipment maintenance and cleaning operations is not known precisely, but is also substantial.

2. Quantities of waste produced will increase significantly as more electricity is generated by coal. The amount of high-volume wastes produced annually could double by the year 2000. In particular, the amount of FGD sludge produced will triple (to about 50 million tons) as newly-constructed power plants install FGD equipment to remove sulfur dioxide from the flue gases.

3. Coal combustion wastes are a common by-product from the generation of electricity. The noncombustible materials are present in the coal as a result of geologic processes and mining techniques. Given current technologies for generating electricity, wastes from coal combustion will continue to be produced in significant quantities.

4. High-volume coal combustion wastes do contain elements that in sufficient concentrations can pose a potential danger to human health and the environment. Most elements in coal are not hazardous. However, trace elements typically found in coal become concentrated as a result of the combustion process. Certain elements known to pose health risks can be found in the wastes at hazardous levels.

5. Although most low-volume wastes do not appear to be hazardous, there are some waste streams from cleaning that could potentially be hazardous. The waste streams of most concern are water-side boiler cleaning solutions, which may be corrosive or toxic. Because the amount and type of low-volume wastes produced can vary substantially from one power plant to the next, not as much is known about low-volume wastes compared to high-volume wastes.

7.2.3 Waste Management Practices

1. Most coal combustion wastes are typically disposed in landfills or surface impoundments, with recent trends toward increased reliance on landfills. Although some disposal does occur off-site, most wastes are disposed on-site; it is likely that most power plants built in the future will dispose on-site in a landfill.

2. Typical industry practice is to co-dispose low-volume wastes with high-volume wastes or, in some instances, to burn the low-volume wastes in the utility boiler. There are many other types of waste management practices that are also used to alter the physical and chemical characteristics of low-volume wastes prior to disposal. These practices vary widely from plant to plant. There are no reliable data sources that accurately describe the types of low-volume disposal practices used at each power plant.

3. The potential for increased waste utilization as a solution to waste management in the utility industry appears to be limited. About 21 percent of all high-volume wastes are currently recycled; some opportunities appear to exist to increase utilization, but not in a major way.

4. Coal combustion wastes are typically regulated under state solid waste laws, which treat these wastes as non-hazardous materials. The

extent of state regulation can vary significantly from one state to another.

5. Many waste management practices applied to hazardous waste in other industries, such as liners, have only seen limited use for coal combustion waste management. In recent years, some of these practices, including liners and leachate collection systems, have become more common. There is an increasing tendency to manage coal combustion wastes by disposing on-site (at the power plant) in landfills.

6. There are few major innovations under development that would lead to major changes in waste management practices.

7.2.4 Potential Hazardous Characteristics

1. The RCRA hazardous characteristics of most concern are corrosivity and EP toxicity. Coal combustion wastes are generally not ignitable or reactive.

2. Most waste streams would not be considered corrosive under RCRA definitions. Only aqueous wastes, which most coal combustion wastes are not, are considered corrosive under RCRA. There are some aqueous coal combustion waste streams that are very near corrosive levels, particularly low volume wastes such as boiler blowdown or coal pile runoff. In some instances, boiler cleaning wastes may be corrosive, particularly those that are hydrochloric acid-based.

3. Coal combustion wastes generally are not EP toxic, although there are some exceptions. It is rare for coal combustion wastes to fail the EP test (or the TCLP test developed more recently). Extract concentrations in excess of 100 times the Primary Drinking Water Standards have been found only for the elements cadmium, chromium, and arsenic from some FGD sludges and coal ash samples, although these levels are quite rare -- average levels are substantially below 100 times the PDWS.

4. There are insufficient data to determine a priori which waste streams at a power plant will exhibit RCRA hazardous characteristics. Accurate determinations could only be made if site-specific analyses were conducted.

7.2.5 Evidence of Environmental Transport of Potentially Hazardous Constituents.

1. Migration of potentially hazardous constituents has occurred from coal combustion waste sites. From the limited data available, exceedances of the Primary Drinking Water Standards have been observed in the ground water for several elements, including cadmium, chromium, lead, selenium, and arsenic.

2. Ground-water contamination does not appear to be widespread. Only a few percent of all ground-water quality observations indicate that a PDWS exceedance has occurred, although many utility waste management

sites at which ground-water monitoring has been done have had at least one exceedance. However, the observed contamination may not necessarily be chronic since sites at which exceedances have been noted do not consistently register in excess of the PDWS.

3. <u>When ground-water contamination does occur, the magnitude of the exceedance is generally not large</u>. Most PDWS exceedances tend to be no more than 10 or 20 times the PDWS, although a few observations greater than 100 times the PDWS have been noted.

4. <u>Human populations are generally not directly exposed to the groundwater in the vicinity of utility coal combustion waste management sites</u>. Public drinking water intakes are usually at least a few kilometers away. Also, most power plants are located near surface water bodies that dilute the concentration of any elements found in the ground water.

5. <u>Because high-volume and low-volume waste streams are often co-disposed, it cannot be determined if one specific waste stream was the source of contamination</u>.

6. <u>The ground-water quality information on which this evidence is based is limited</u>. Data were only available from a small number of utility waste management sites; no comprehensive database on ground-water contamination potentially attributable to coal combustion wastes exists.

7.2.6 Evidence of Damage

1. There are few cases considered to be documented evidence of damage from coal combustion wastes. Among these cases there is some dispute whether any observed damage can be attributed to the utility waste management facility.

2. Damage cases are dominated by chronic incidents (seepage, periodic runoff) as opposed to catastrophic incidents (sudden releases, spills), although one documented damage case was due to structural failure of a surface impoundment.

3. Documented damage typically involves physical or chemical degradation of ground water or surface water, including fish kills or reduction in biota, but seldom involves direct effects on human health because the water is not consumed for drinking water purposes. Much of the damage has occurred in the immediate vicinity of the waste management site; drinking water intakes are generally far enough away such that any contaminated water is not being directly used for human consumption.

7.2.7 Potential Costs of Regulation

1. If additional regulations are promulgated for utility waste management, the total costs incurred by the industry could vary considerably depending on the extent of the additional regulations.

For example, total annual costs to install and operate ground-water monitoring systems would be unlikely to exceed $10 million. On the other hand, total annual costs for the industry could approach $5 billion if all existing facilities were capped and closed and new facilities were constructed with liners, leachate collection systems, flood protection, and ground-water monitoring. (Corrective action costs, such as excavating all existing facilities for removal of the wastes to RCRA Subtitle C facilities, are not included in this estimate; such costs would be extremely high.)

2. <u>Regulation of utility coal combustion wastes under full RCRA Subtitle C requirements could halt all recycling of coal combustion wastes if recycling was also subject to Subtitle C requirements</u>. Total costs to the industry could approach $2.4 billion annually. If recycled wastes were not subject to Subtitle C disposal requirements, it is possible the amount of recycling could increase as the utility industry increased waste utilization to avoid full Subtitle C disposal costs.

3. <u>The costs to the utility industry for full RCRA Subtitle C compliance could decrease the amount of coal consumed in coal-fired power plants</u>. The costs of generating electricity with coal could increase by several percent (depending on the extent of additional regulations), making it economic to generate electricity with other fuels. These impacts could be felt in two ways: 1) lower coal consumption at existing power plants and 2) construction of fewer coal-fired power plants in the future.

7.3 RECOMMENDATIONS

Based on the findings from this Report to Congress, this section presents the Agency's preliminary recommendations for those wastes included in the scope of this study. The recommendations are subject to change based on continuing consultations with other government agencies and new information submitted through the public hearings and comments on this report. Pursuant to the process outlined in RCRA 3001(b)(3)(C), EPA will announce its regulatory determination within six months after submitting this report to Congress.

First, EPA has concluded that coal combustion waste streams generally do not exhibit hazardous characteristics under current RCRA regulations. EPA does not intend to regulate under Subtitle C fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes. EPA's tentative conclusion is that current waste management practices appear to be adequate for protecting human health and the environment. The Agency prefers that these wastes remain under Subtitle D authority. EPA will use section 7003 of RCRA and sections 104 and 106 of CERCLA to seek relief in any cases where wastes from coal combustion waste disposal sites pose substantial threats or imminent hazards to human health and the environment. Coal combustion waste problems can also be addressed under RCRA Section 7002, which authorizes citizen lawsuits for violations of Subtitle D requirements in 40 CFR Part 257.

Second, EPA is concerned that several other wastes from coal-fired utilities may exhibit the hazardous characteristics of corrosivity or EP toxicity and merit regulation under Subtitle C. EPA intends to consider whether these waste streams should be regulated under Subtitle C of RCRA based on further study and information obtained during the public comment period. The waste streams of most concern appear to be those produced during equipment maintenance and water purification, such as metal and boiler cleaning wastes. The information available to the Agency at this time does not allow EPA to determine the exact quantity of coal combustion wastes that may exhibit RCRA Subtitle C characteristics. However, sufficient information does exist to indicate that some equipment maintenance and water purification wastes do occasionally exhibit RCRA hazardous characteristics, and therefore, may pose a danger to human health and the environment. These wastes are similar to wastes produced by other industries that are subject to Subtitle C regulation, and waste management practices for coal combustion wastes are often similar to waste management practices employed by other industries. EPA is considering removing the exemption for all coal-fired utility wastes other than those identified in the first recommendation. The effect would be to apply Subtitle C regulation to any of those wastes that are hazardous by the RCRA characteristic tests. EPA believes there are various treatment options available for these wastes that would render them nonhazardous without major costs or disruptions to the utilities.

Third, EPA encourages the utilization of coal combustion wastes as one method for reducing the amount of these wastes that need to be disposed to the extent such utilization can be done in an environmentally safe manner. From the information available to the Agency at this time, current waste utilization practices appear to be done in an environmentally safe manner. The Agency supports voluntary efforts by industry to investigate additional possibilities for utilizing coal combustion wastes.

Through its own analysis, evaluation of public comments, and consultation with other agencies, the Agency will reach a regulatory determination within six months of submission of this Report to Congress. In so doing, it will consider and evaluate a broad range of management control options consistent with protecting human health and the environment. Moreover, if the Agency determines that Subtitle C regulation is warranted, in accordance with Section 3004(x) EPA will take into account the "special characteristics of such waste, the practical difficulties associated with implementation of such requirements, and site-specific characteristics . . .," and will comply with the requirements of Executive Orders 12291 and 12498 and the Regulatory Flexibility Act.

GLOSSARY

acidity - the amount of free carbon dioxide, mineral acids and salts (especially sulfates or iron and aluminum) which hydrolyze to give hydrogen ions in water and is reported as milli-equivalents per liter of acid, or ppm acidity as calcium carbonate, or pH the measure of hydrogen ions concentration. Indicated by a pH of less than 7.

administrator - the Administrator of the United States Environmental Protection Agency, or his/her designee.

alkaline cleaning solution wastes - water-side cleaning waste resulting from the removal of high copper content scale from the utility boiler.

alkaline passivating waste - water-side cleaning waste resulting from the removal of iron and copper compounds and silica to neutralize acidity after acid cleaning.

alkalinity - the amount of carbonates, bicarbonates, hydroxides and silicates or phosphates in the water and is reported as grains per gallon, pH, or ppm of carbonate. Indicated by a pH of greater than 7.

alkaline fly ash scrubber - a flue gas desulfurization system in which flue gas reacts with alkaline fly ash that is augmented with a lime/limestone slurry.

anthracite - a high ASTM ranked coal with dry fixed carbon 92% or more and less than 98%; and dry volatile matter 8% or less and more than 2% on a mineral-matter-free basis.

aquifer - a water-bearing bed or structure of permeable rock, sand, or gravel capable of yielding quantities of water to wells or springs.

ash - the incombustible solid matter in fuel.

ash fusion - the temperatures at which a cone of coal or coke ash exhibits certain melting characteristics.

attenuation - a process that slows the migration of constituents through the ground.

baghouse - an air pollution abatement device used to trap particulates by filtering gas streams through large fabric bags usually made of glass fibers.

base load - base load is the term applied to that portion of a station or boiler load that is practically constant for long periods.

batch test - a laboratory leachate test in which the waste sample is placed in, rather than washed with, leachate solution.

bituminous coal - ASTM coal classification by rank on a mineral/matter-free basis and with bed moisture only.

<u>low</u> <u>volatile</u>: dry fixed carbon 78% or more and less than 86%; and dry volatile matter 22% or more and less than 14%.
<u>medium</u> <u>volatile</u>: dry fixed carbon 69% or more and less than 78%; and dry volatile matter 22% or more and less than 31%.
<u>high</u> <u>volatile</u> <u>(A)</u>: dry fixed carbon less than 69% and dry volatile matter more than 31% - Btu value equal to or greater than 14,000 moist, mineral-matter-free basis.
<u>high</u> <u>volatile</u> <u>(B)</u>: Btu value 13,000 or more and less than 14,000 moist, mineral-matter-free basis.
<u>high</u> <u>volatile</u> <u>(C)</u>: Btu value 11,000 or more and less than 13,000 moist, mineral-matter-free basis commonly agglomerating, or 8,300

to 11,500 Btu agglomerating.

blower - the fan used to force air through a pulverizer or to force primary air through an oil or gas burner register.

boiler - a closed vessel in which water is heated, steam is generated, steam is superheated, or any combination thereof, under pressure or vacuum by the application of heat.

boiler blowdown - removal of a portion of boiler water for the purpose of reducing solid concentration or discharging sludge.

boiler cleaning waste - waste resulting from the cleaning of coal combustion utility boilers. Boiler cleaning wastes are either water/side or gas-side cleaning wastes.

boiler slag - melted and fused particles of ash that collect on the bottom of the boiler.

boiler water - a term used to define a representative sample of the boiler circulating water. The sample is obtained after the generated steam has been separated and before the incoming feedwater or added chemical becomes mixed with it so that its composition is affected.

bottom ash - large ash particles that settle on the bottom of the boiler.

British Thermal Unit (Btu) - the mean British Thermal Unit is 1/180 of the heat required to raise the temperature of 1 pound of water from $32^{o}F$ to $212^{o}F$ at a constant atmospheric pressure. It is about equal to the quantity of heat required to raise 1 pound of water 1 degree F.

capacity factor - the total output over a period of time divided by the product of the boiler capacity and the time period.

CERCLA - The Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as Superfund.

cell - a section of a landfill, or the size of that section. Usually only a few cells of a landfill are open to accept waste at a time.

chain grate stoker - a stoker which has a moving endless chain as a grate surface, onto which coal is fed directly from a hopper.

coal pile runoff - surface runoff from a plant's coal pile.

cogeneration - the production of steam (or hot water) and electricity for use by multiple users generated from a single source.

column test - a leachate extraction procedure that involves passing a solution through the waste material to remove soluble constituents.

contingency plan - a document setting out an organized, planned, and coordinated course of action to be followed in case of a fire or explosion or a release of hazardous waste constituents into the environment.

cooling tower blowdown - water withdrawn from the cooling system in order to control the concentration of impurities in the cooling water.

cyclone furnace - specialty furnace for high intensity heat release. So named because of its swirling gas and fuel flows.

demineralizer regeneration and rinses waste - a low volume wastewater generated from the treatment of water to be used at the plant.

direct lime flue gas desulfurization - see lime/limestone FGD process.

direct limestone flue gas desulfurization - see lime/limestone FGD process.

disposal - the discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste or hazardous waste into or on any land or water such that any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters.

dry-bottom furnace - a pulverized-fuel furnace in which ash particles are deposited on the furnace bottom in a dry, non-adherent condition.

dry scrubber - an FGD system for which sulfur dioxide is collected by a solid medium; the final product is totally dry, typically a fine powder.

dry sorbent injection - an FGD system in the research and development stage for which a powdered sorbent is injected into the flue gas before it enters the baghouse. Sulfur dioxide reacts with the reagent in the flue gas and on the surface of the filter in the baghouse.

dual alkali fly ash scrubber - a flue gas desulfurization system similar to the lime/limestone process, except that the primary reagent is a solution of sodium salts and lime.

effluent - a waste liquid in its natural state or partially or completely treated that discharges in to the environment from a manufacturing or treatment process.

electrostatic precipitator - an air pollution control device that imparts an electrical charge to particles in a gas stream causing them to collect on an electrode.

evapotranspiration - the combined process of evaporation and transpiration.

fabric filter - a cloth device that catches dust and particles from industrial or utility emissions.

flash point - the lowest temperature at which vapors above a volatile combustible substance ignite in air when exposed to flame.

flue gas - the gaseous products of combustion in the flue to the stack.

flue gas desulfurization (FGD) sludge - waste that is generated by the removal of some of the sulfur compounds from the flue gas after combustion.

fly ash - suspended ash particles carried in the flue gas.

furnace - the combustion chamber of a boiler.

gas-side cleaning waste - waste produced during the removal of residues (usually fly ash and soot) from the gas-side of the boiler (air preheater, economizer, superheater, stack, and ancillary equipment).

ground water - water found underground in porous rock strata and soils.

ground water monitoring well - a well used to obtain ground-water samples for water-quality analysis.

hazardous waste - a solid waste, or combination of solid wastes, which, because of its quantity, concentration, or physical, chemical, or infectious characteristics, may (1) cause, or significantly contribute to, an increase in serious irreversible, or incapacitating reversible illness; or (2) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, disposed of, or otherwise managed.

hard water - Water that contains sufficient dissolved calcium and magnesium to cause a carbonate scale to form when the water is boiled or to prevent the sudsing of soap in the water.

high volume waste - fly ash, bottom ash, boiler slag, and flue gas desulfurization sludge.

hydraulic conductivity - the quantity of water that will flow through a unit cross-sectional area of a porous material per unit of time.

hydrochloric acid cleaning waste - wastes from the cleaning of scale caused by water hardness, iron oxides, and copper.

land disposal - the placement of wastes in a landfill, surface impoundment, waste pile, injection well, land treatment facility, salt dome formation, salt bed formation, or underground mine or cave.

landfill - a disposal facility or part of a facility where hazardous waste is placed in or on land and which is not a land treatment facility, a surface impoundment or injection well.

leachate - the liquid resulting from water percolating through, and dissolving materials in, waste.

leachate extraction test - a laboratory procedure used to predict the type and concentration of constituents that will leach out of waste material.

leachate collection, removal, and treatment systems - mitigative measures used to prevent the leachate from building up above the liner.

lift - the depth of a cell in a landfill.

lignite - a coal of lowest ASTM ranking with calorific value limits on a moist, mineral-matter-free basis less than 8,300 Btu.

lime - calcium oxide ($CaCO3$), a chemical used in some FGD systems.

limestone - calcium carbonate ($CaOH2$), a chemical used in some FGD systems.

lime/limestone FGD process - form of wet non-recovery flue gas desulfurization system in which flue gases pass through a fly ash collection device and into a contact chamber where they react with a solution of lime or crushed limestone to form a slurry which is dewatered and disposed.

liner - a mitigative measure used to prevent ground-water contamination in which synthetic, natural clay, or bentonite materials that are compatible with the wastes are used to seal the bottom or surface impoundments and landfills.

low volume waste - wastes generated during equipment maintenance and water purification processes. Low volume wastes include boiler cleaning solutions, boiler blowdown, demineralizer regenerant, pyrites, cooling tower blowdown.

mechanical stoker - a device consisting of mechanically operated fuel feeding mechanism and a grate, and is used for the propose of feeding solid fuel into a furnace, and to distribute it over a grate, admitting air to the fuel for the purpose of combustion, and providing a means for removal or discharge of refuse.

net recharge - the amount of precipitation absorbed annually into the soil.

off-site - geographically noncontiguous property, or contiguous property that is not owned by the same person. The opposite of on-site.

on-site - the same or geographically contiguous property which may be divided by public or private right(s)-of-ways, provided the entrance and exit between the properties is at across-roads, intersection, and access is by crossing as opposed to going along the right(s)-of-way. Noncontiguous properties owned by the same person but connected by a right-of-way which the person controls and to which the public does not have access, is also considered on-site property.

Part A - the first part of the two part application that must be submitted by a TSD facility to receive a permit. It contains general facility information.

Part B - the second part of the two part application that includes detailed and highly technical information concerning the TSD in question. There is no standard form for the Part B, instead the facility must submit information based on the regulatory requirements.

particulates - fine liquid or solid particles such as dust, smoke, mist, fumes, or smog, found in the air or emissions.

permeability (1) - the ability of a geologic formation to transmit ground water or other fluids through pores and cracks.

permeability (2) - the rate at which water will seep through waste material.

petroleum coke - solid carbaceous residue remaining in oil refining stills after distillation process.

pH - a measure of the acidity or alkalinity of a material, liquid or solid. pH is represented on a scales of 0 to 14 with 7 being neutral state, 0 most acidic and 14 most alkaline.

plume - a body of ground water originating from a specific source and influenced by such factors as the local ground-water flow pattern and character of the aquifer.

pond liquors - waste fluid extracted from a surface impoundment or landfill.

pozzolanic - forming strong, slow-hardening cement-like substance when mixed with lime or other hardening material.

PDWS - Primary Drinking Water Standards established by the Safe Drinking Water Act.

pulverizer - a machine which reduces a solid fuel to a fineness suitable for burning in suspension.

pyrites - solid mineral deposits of raw coal that are separated from the coal before burning.

reagent - a substance that takes part in one or more chemical reactions or biological processes and is used to detect other substances.

recharge - the replenishment of ground water by infiltration of precipitation through the soil.

RCRA - Resource Conservation and Recovery Act, as amended (Pub. L. 94-580). The legislation under which EPA regulates solid and hazardous waste.

RCRA Subtitle C Characteristics - criteria used to determine if an unlisted waste is a hazardous waste under Subtitle C of RCRA.

- corrosivity - a solid waste is considered corrosive if it is aqueous and has a pH less than or equal to 2 or greater than or equal to 12.5 or if it is a liquid and corrodes steel at a rate greater than 6.35 mm per year at a test temperature of 55°C.

- EP toxicity - a solid waste exhibits the characteristic of EP (extraction procedure) toxicity if, after extraction by a prescribed EPA method, it yields a metal concen- tration 100 times the acceptable concentration limits set forth in EPA's primary drinking water standards.

- ignitability - a solid waste exhibits the characteristic of ignitability if it is a liquid with a flashpoint below 60°C or a non-liquid capable or causing fires at standard temperature and pressure.

- reactivity - a waste is considered reactive if it reacts violently, forms potentially explosive mixtures, or generates toxic fumes when mixed with water, or if it is normally unstable and undergoes violent change without deteriorating.

SDWS - Secondary Drinking Water Standards established by the Safe Drinking Water Act.

settling lagoon - surface impoundment.

shear strength - the resistance offered by a material subjected to a compressive stress created when two contiguous parts of the material are forced in opposite parallel directions.

slag - molten or fused solid matter.

sludge - a soft water-formed sedimentary deposit that is mud-like in its consistency.

slurry - a mixture of insoluble mater in a fluid.

solid waste - As defined by RCRA, the term "solid waste" means any garbage, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations, and from community activities, but does not include solid or dissolved material in domestic sewage, or solid or dissolved materials in irrigation return flows or industrial discharges which are point sources subject to permits under the Clean Water Act, or special nuclear or byproduct material as defined by the Atomic Energy Act of 1954.

spray drying process - a flue gas desulfurization system in which a fine spray of alkaline solution is injected into the flue gas as it passes through a contact chamber, where the reaction with the sulfur oxides occurs. The heat of the flue gas evaporates the water in the solution, leaving a dry powder, which is collected by a particulate collector.

stabilization - making resistant to physical or chemical changes by treatment.

steady state - an adjective that implies that a system is in a stable dynamic state in which inputs balance outputs.

stoker - see mechanical stoker.

storage - the holding of waste for a temporary period, at the end of which the hazardous waste is treated, disposed of, or stored elsewhere.

subbituminous coal - An intermediate rank coal between lignite and bituminous with more carbon and less moisture than lignite.

sump effluent - waste from sumps that collect floor and equipment drains.

surface impoundment - a facility which is a natural topographic depression, artificial excavation, or diked area formed primarily of earthen materials (although it may be lined with artificial materials), which is designed to hold an accumulation of liquid wastes or wastes containing free liquids.

surface water - water that rests on the surface of the rocky crust of the earth.

traveling grate stoker - a stoker similar to a chain grate stoker except that the grate is separate from but is supported on and driven by chains.

trace element - An element that appears in a naturally-occurring concentration of less than 1 percent.

treatment - any method, technique, or process, including neutralization, designed to change the physical, chemical, or biological character or composition of a waste so as to neutralize it, recover it, make it safer to transport, store or dispose of, or amenable for recovery, storage, or volume reduction.

TSD facility - waste treatment, storage, or disposal facility.

utility boiler - a boiler which produces steam primarily for the production of electricity in the utility industry.

volatile - A volatile substance is one which tends to vaporize at a relatively low temperature.

water-side cleaning waste - waste produced during the removal of scale and corrosion products from the water side of the boiler (i.e., the piping systems containing the steam or hot water).

wet bottom furnace - a pulverized fuel fired furnace in which the ash particles are deposited and retained on the floor thereof and molten ash is removed by tapping either continuously or intermittently. (also called a slag tap furnace)

wet scrubber - a device utilizing a liquid, designed to separate particulate matter or gaseous contaminants from a gas stream by one or more mechanisms such as absorption, condensation, diffusion, inertial impaction.

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Table 4.1: CCR VERSUS CAMA

FACTOR	N.C. CAMA Coal Ash Management Act of 2014. Law on 8/20/2014	EPA CCR RULE Final on 12/19/2014 and Effective on 10/06/2016	CAMA Amendments Law on 7/14/2016	Water Infrastructure Improvements for the Nation (WIIN) Act of 2016. Law on 12/16/2016.
1. APPLICABILITY	All ash basins , landfills, and beneficial reuses. Focus is on basin closure.	Surface impoundments, landfills, and inactive surface impoundments that impound water at stations with generation. Beneficial uses. Regulates CCR disposal.	Deletes references to Coal Ash Management Commission. Review of DEQ's quarterly reports left to Environmental Review Commission.	Establishes a state permit program for coal ash impoundments to be supervised by the U.S. Environmental Protection Agency. Amends the Resource Conservation and Recovery Act (RCRA), changing the EPA's self-implementing coal ash rule into an EPA-authorized state permit program. The EPA will only approve of the state programs if they incorporate already-established federal requirements.
2. BASIN CLOSURE	Required timing is based on risk rankings or "High Priority" designation.	Required if basins cannot meet various safety and environmental criteria. High priority is placed on stability evaluation.		
3. BASIN EVALUATION	All basins must close. Subjective risk ranking determines closure method. Ash basins to be risk-ranked by NCDEQ based on 9 factors in CAMA. CAMC reviews and approves risk rankings.	Basins can remain operating. Demonstrations that basins meet all Dam Safety, Liner, Groundwater, and Location restrictions must be made within 18 to 42 months of rule publication. Basins must be closed if demonstrations can't be made.	§ 130A-309.213. Prioritization of coal combustion residuals surface impoundments. Deletes specific criteria under (a) to be evaluated by DEQ in assessing surface impoundment risk. (d)(1) requires the DEQ to a low risk classification if it (a) Has established permanent water supplies as required for the impoundment pursuant to G.S. 130A-309.211(c1) and (b) Has rectified any deficiencies identified by, and otherwise complied with the requirements of, any dam safety order issued by the Environmental Management Commission for the impoundment pursuant to G.S. 143-215.32. (c) Other impoundments are classified as intermediate risk. § 130A-309.216. Ash beneficiation projects (new)	
4. CLOSURE METHOD	Cap in place allowed for "low risk" basins only. Clean closure via excavation required for "high priority", "high risk", and "intermediate risk" impoundments.	Cap in place and clean closure allowed. Requirements for each method is provided.		
5. CLOSURE TIMING	Closure timing is tied to risk ratings: 5, 10, or 15 years.	Forced closures within 5 years with possible extensions for certain factors (i.e., no alternate capacity available, size of impoundment). Up to 15.5 years in some cases.		
6. CONVERSION TO DRY ASH DISPOSAL	Requires dry fly ash disposal by Dec 2018 and dry bottom ash disposal by Dec 2019.	Does not expressly address conversion to dry ash disposal. However, in some cases, conversion is driven by basin closure requirements. EPA extended timelines to accommodate Steam Electric Effluent Limitations Guidelines that proposes to require conversion to dry ash disposal.		
7. ENFORCEMENT	State regulatory agency with Coal Ash Management Committee oversight. Enforcement through state agency action.	Self-implementing. Enforced through citizen suits in federal court.		TITLE II--WATER AND WASTE ACT OF 2016 Subtitle C--Control of Coal Combustion Residuals. (Sec. 2301) This bill amends the subtitle D (Resource Conservation and Recovery Act of 1976) of the Solid Waste Disposal Act to establish a permit program for coal combustion residuals (coal ash) that states, after approval by the EPA, may elect to administer in lieu of a federal regulatory program. The EPA must review the programs at least once every 12 years, or on the request of a state. The EPA may use specified authorities to enforce the prohibition against open dumping with respect to a coal combustion residual unit.

8. GROUNDWATER MONITORING	Groundwater assessment required 180 days after DEQ's approval of the plan (pending??). Monitoring done at compliance boundary. Measuring for 15A NCAC 02L.0202 criteria (limit in parentheses). In Items IV.134-185 of the Plea Agreement, Duke acknowledged that water from seeps may transport pollutants such as aluminum (NL), arsenic (10 µg/L), barium (700 µg/L), boron (700 µg/L), cadmium (2 µg/L), chloride (250 mg/L), chromium (100 µg/L), copper (1 mg/L), fluoride (2 mg/L), iron (300 µg/L), lead (15 µg/L), manganese (50 µg/L), nickel (100 µg/L), selenium (20 µg/L), sulfate (250 mg/L), thallium (NL), zinc (1 mg/L), and TDS (NL).	Required within 30 months of rule publication (DATE). Monitoring done at waste boundary. Measuring for statistically significant increases over background (CONSTITUENTS AND LEVELS).	Review of DEQ's quarterly reports left to Environmental Review Commission. § 130A-309.211. Groundwater assessment and corrective action; drinking water supply well survey and provision of alternate water supply; reporting. New (c1) requires no later than October 15, 2018, the owner of a coal combustion residuals surface impoundment shall establish permanent replacement water supplies for (I) each household that has a drinking water supply well located within a one-half mile radius from the established compliance boundary of a coal combustion residuals impoundment, and is not separated from the impoundment by the mainstem of a river, as that term is defined under G.S. 143-215.22G, or other body of water that would prevent the migration of contaminants through groundwater from the impoundment to a well and (ii) each household that has a drinking water supply well that is located in an area in which contamination resulting from constituents associated with the presence of a coal combustion residuals impoundment is expected to migrate.	
9. STRUCTURAL FILLS	Governed as beneficial reuse solution with specific permitting and construction criteria (SPECIFY). CAMA regulated structural fills >8,000 tpy or 80,000 tons per project. Small structural fills <8,000 tons per acre or 80,000 tons per project are deemed permitted. Large SF >8,000 tons per acre or 80,000 tons per project require liners, caps, leachate control, groundwater monitoring, and financial assurance. NC CCP rule will add requirements to make as stringent as EPA CCR.	Must qualify as beneficial reuse under the rule or meet the requirements for a CCR landfill. EPA CCR requires reporting and environmental demonstrations for fills >12,400 tons.		
10. BENEFICIAL USE OF CCP	Draft of State CCP rule to be consistent with CAMA, coordinated with NCDOT and UNC Charlotte, and go to EMC in July 2016. NCDEQ will incorporate into current DWM and DWR beneficial use/reuse rules.			
11. COMPREHENSIVE SITE ASSESSMENTS (CSA) AND CORRECTIVE ACTION PLANS (CAP)	CSA and CAP containing over 1,000 pages each were submitted by Duke to NCDEQ. Largest investigation of its kind was completed over six months. Duke drilled over 870 wells and collected over 7,000 samples. However, this extensive work could not determine the horizontal and vertical extent of contamination or background levels of constituents critical to prioritization. **DEQ is unable to determine with current (12/31/15) data is Duke coal as ponds are impacting wells but there are known impacts at Sutton and Asheville.** In 476 wells sampled, DHHS issued do not drink notices for 424 wells mainly for vanadium and hexavalent chromium BUT only 12 wells exceeded SDWA levels (7 for lead and 5 for arsenic) which could be attributed to poor well construction (lead) or naturally occurring (arsenic).			
12. DECANTING AND DEWATERING	On August 28, 2014, NCDEQ authorized decanting to begin under existing NPDES permits. Complete dewatering requires NPDES permit modification but is necessary for wet ash removal and must address engineered and non-engineered seeps. NPDES permits are on hold for 13 of 14 Duke facilities.	On September 10, 2014, EPA ordered NC decanting halted. On December 14, 2015, EPA authorized NC to resume decanting but is still unsure on permitting seeps that may be "waters of the US" -- a problem at 894 US impoundments. EPA appears to be backing away from written Hanlon Policy.		
13. GROUNDWATER AND DRINKING WATER STANDARDS	NC DHHS has the lowest groundwater standard (10 ppb) in the US but issues do not drink notices for 0.07 ppb for Cr(VI) and 0.03 ppb for Vanadium. More than 70% of the US public water supplies exceed DHHS screening levels for Cr(VI) or Vanadium.	Federal SWDA standard is 100 ppb Total Chromium and has no standard for Vanadium.		

Table 4.2: CCR State Rules and Regs

FACTOR	Kentucky	West Virginia	Virginia	Tennessee	Georgia	South Carolina
1. APPLICABILITY	401 KAR 4:070. Applicability established by EPA CCR rule.	W.VA.REGS. 33-1-5. Adopts federal regulations.	9 VAC 20-60-261. Adopted federal regulations. Senate Bill 1533 from January 2019 requires CCR be removed for recycling or deposition in a lined landfill.	TN Rule 0400-11-01-.02	GA Rule 391-3-11. Adopts federal regulations.	SC Code Regs 61-79.261 establishes regulations for CCR impoundments as exempt from solid waste designation.
2. BASIN CLOSURE	401 KAR 4:070. Closure procedure established by EPA CCR rule	W.VA.REGS. 33-1-5. Adopts federal regulations.	9 VAC 20-60-261. Adopted federal regulations. In January 2019 Senate Bill 1533 requires that any CCR unit located in the Chesapeake Bay watershed be closed by recycling/beneficial use or deposition in a permitted and lined landfill.		GA Rule 391-3-11. Adopts federal regulations.	
3. BASIN EVALUATION		W.VA.REGS. 33-1-5. Adopts federal regulations.	Senate Bill 1398 required every owner/operator of CCR impoundments to conduct an assessment regarding closure of the unit, no later than December 1, 2017.	TDEC Order OGC15-0177 (to TVA). TVA shall conduct an investigation of CCR disposal areas listed in the order, to collect groundwater and other environmental data.		
4. CLOSURE METHOD	401 KAR 4:070. Closure procedure established by EPA CCR rule	W.VA.REGS. 33-1-5. Adopts federal regulations.	Senate Bill 1398 requires every owner/operator of CCR impoundments to conduct an assessment regarding closure of the unit, no later than December 1, 2017. January 2019's Senate Bill 1533 requires recycling or removal to a lined landfill.	Cap in place allowed. The TDEC order to the TVA requires a corrective action risk assessment plan that includes the methods TVA will employ to remove and/or close in place CCR material at the sites.		
5. CLOSURE TIMING	401 KAR 4:070. Closure procedure established by EPA CCR rule	W.VA.REGS. 33-1-5. Adopts federal regulations.	Senate Bill 1398 required every owner/operator of CCR impoundments to conduct an assessment regarding closure of the unit, no later than December 1, 2017. Senate Bill 1533 requires closure projects to be complete within 15 years of their initiation.			
6. CONVERSION TO DRY ASH DISPOSAL						
7. ENFORCEMENT	401 KAR 46:120. Permits given by state regulatory agency.	W.VA.REGS. 33-1-5. Adopts federal regulations.	9 VAC 20-60-261. Adopted federal regulations.			

8. GROUNDWATER MONITORING	401 KAR 46:110. Groundwater monitoring and corrective action are established in the EPA CCR rule.	W.VA.REGS. 33-1-5. Adopts federal regulations.	9 VAC 20-60-261. Adopts federal regulations. Senate Bill 1533 requires closure projects to be accompanied by water testing for every residence within one-half mile.	TDEC Order OGC15-0177 calls for plans to address groundwater monitoring for the future of the CCR impoundment	GA Rule 391-3-11. Adopts federal regulations.	
9. STRUCTURAL FILLS				TN Rule 0400-11-01-.02. Disposal is limited to coal ash in engineered structures for highway overpasses, levees, runways, or foundation backfill.	Not specifically authorized under Georgia law or regulations	Not specifically authorized under SC law or regulations. Regulations were drafted in 1994 by SCDHEC but were withdrawn.
10. BENEFICIAL USE OF CCP		CCRs may be reused as material in manufacturing another product or as a substitute for a natural resource, for the extraction of recovery materials and compounds contained within the CCRs, as a stabilization/solidification agent for other wastes, under the authority of the WVDoE, as pipe bedding, as antiskid material, as a construction base for roads or parking lots. W.VA.REGS. 33-1-5.5.b.4.A-H	Senate Bill 1533 requires that any owner of a CCR unit explain why recycling is not economically feasible if they choose to landfill the CCR instead.			
11. COMPREHENSIVE SITE ASSESSMENTS (CSA) AND CORRECTIVE ACTION PLANS (CAP)						
12. DECANTING AND DEWATERING						
13. GROUNDWATER AND DRINKING WATER STANDARDS	401 KAR 46:110. Groundwater monitoring and corrective action are established in the EPA CCR rule.	W.VA.REGS. 33-1-5. Adopts federal regulations.	9 VAC 20-60-261. Adopted federal regulations. Senate Bill 1522 in January 2019 required closure projects to be accompanied by water testing or a connection to municipal water for every residence within one-half mile.		GA Rule 391-3-11. Adopts federal regulations.	

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THE DISPOSAL AND RECLAMATION OF SOUTHWESTERN COAL AND URANIUM WASTES

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1.0 INTRODUCTION

One of the major environmental problems confronting the coal and uranium industries of the Southwest is the disposal and reclamation of the large volumes of wastes produced by mining, processing, and on-site utilization of these resources. Wastes and drainages are produced during coal mining and cleaning, and the burning of coal in modern boilers produces large quantities of ash and sludge. Likewise, uranium mining and milling generates large amounts of solid and liquid waste materials. The wastes from both of these industries must be carefully deposited in waste disposal sites, and reclamation measures taken to ensure their long term stability. In this paper, the types of wastes produced by the coal and uranium industries in the Southwest will be described, some of the potential environmental impacts from these materials will be considered, and the procedures in current use for the disposal and reclamation of these wastes will be discussed.

2.0 DISPOSAL AND RECLAMATION OF COAL WASTES

Coal is a type of combustible rock that is formed from plant remains and various inorganic components. Because of this, coal is a highly heterogeneous material that contains a wide variety of rock and mineral impurities in addition to the carbon-like matrix. Most of the environmental contamination and waste materials produced by coals are a direct consequences of these impurities.

In each step of the coal processing cycle, from mine to eventual utilization, various wastes or effluents are produced that must be treated, stored, or disposed of (Fig. 1.). These for the most part are high volume wastes that have the potential for causing great environmental damage if not properly handled. The coal industry of the Southwest is still in its infancy, but dramatic increases in the use of coal from the region (with the accompanying necessity to devote greater attention and resources to waste disposal and reclamation) will be necessary if our nation is to decrease its dependence on foreign energy sources and meet future energy needs.

2.1 COAL MINING WASTES

Coal is removed from the earth by two principal kinds of mining: strip mining and underground mining. In the Southwest, strip mining is the dominant form of coal extraction because most of the coal now being mined in this region is deposited relatively close to the surface.[1] In the strip mining of coal, heavy equipment such as power shovels, bulldozers, trucks, and draglines are used to remove the overburden and expose the coal seam, and remove the coal from the mine pit. In the past, many strip mines were simply abandoned with little or no effort to reclaim them after the accessible coal had been removed, but with the passage of the federal Surface Mining Control and Reclamation Act (1977) such practices are no longer allowable. Strip mine reclamation has become an integral part of the mining operation.

The surface mining act specifies that all surface soil must be carefully removed during mine development and stored so that it can be used later during reclamation. The remaining overburden must also be stored for reuse. As the coal is removed from the ground, the overburden is progressively backfilled into the previously mined areas. When the mining operation is completed the remaining overburden is put into the mine, the top soil is replaced, and native ground cover is reestablished.

Although adherence to the federal strip mine act eliminates the necessity to separately dispose of solid mine wastes, the problem of ground water contamination or disruption during or subsequent to mining remains a bothersome problem without an easy solution. Much of the strippable coal in the southwestern region lies above major aquifers, but for that which does not, diversion and pumping of water from mining sites must be done. After mining is completed, it is very difficult to restore the condition of the original aquifers. Western coals and coal spoils are far less likely to produce contaminated drainages when gro water passes through them than are eastern coals;[2] however, it would be a recommended practice to monitor the groundwater downfield from recently reclaimed mining areas to assure that undesirable contaminants are not being released.

In the underground mining of coal, access shafts are sunk vertically into the coal seam or mine shafts are bored directly into coal outcroppings; from these access points mine tunnels are distributed into the coal seam. Conventional room and pillar mining is most often practiced in the underground mining of coal; however, some highly mechanized forms of mining, such as long-wall mining, are becoming more popular where conditions permit their use.[3]

The underground mining of coal produces a large amount of spoil or mineral wastes. These are the overburden and rock removed from the mine shafts while gaining access to the coal seams, and the rock intrusions in the seams themselves. It has not yet proven feasible to replace underground mine spoils back into the mine, so these wastes must be discarded at the surface. The usual practice for disposing and re laiming western mine spoils is to place them into a depression or gully, were they can be compacted and graded to prevent erosion and perhaps seeded with native vegetation.[4] Nearby strip mines also provide a convenient place for the disposal of underground mine spoils.

One of the most serious environmental problems associated with the underground mining of southwestern coals is the possible disruption and degradation of aquifers located in the coal seam or associated strata. There are no effective remedial measures for restoring the original aquifer drainage once mining has disrupted it. Therefore, the best means of avoiding aquifer damage during underground coal mining is to preplan the mining operation with as much knowledge as possible of the geohydrology of the area.

2.2 COAL CLEANING WASTES

Coal, as mined, contains a great deal of extraneous rock and mineral matter. These constituents usually comprise about 10% to 20% of raw coals, but they can run as high as 50% for some coals.[5] The rock and mineral matter is expensive to ship, and it dilutes the energy content of the coal, but, of most importance from an environmental viewpoint, these impurities produce undesirable gaseous and particulate pollutants when the coal is burned. Therefore, about one-half of the total coal mined in the United States is prepared or cleaned prior to utilization to remove some of the noncombustible materials. Currently little western coal is washed or cleaned before combustion, but the demand for higher quality coal will undoubtedly result in a higher proportion of these coals being cleaned in the future.

Coal cleaning is largely a mechanical process, involving a series of crushing, sizing, separating and drying steps. In most cases, the coal is separated from the mineral matter on the basis of density. Modern coal preparation plants can recover about 90% of the energy content of the coal, while reducing the mineral content of the coal considerably.[6]

The wastes produced by coal cleaning are similar in composition to the spoil materials produced by coal mining. However, because cleaning wastes are more finely divided than mine wastes, they present a greater problem with regard to disposal and reclamation. The drainages from cleaning waste disposal sites are often contaminated with dissolved and suspended solids.[7] Also, because they contain some residual coal, cleaning waste dumps frequently catch fire; and, because of the poor structural quality of coal cleaning wastes, disposal areas for these materials often exhibit structural instabilities.[7]

The disposal and reclamation of coal cleaning wastes is governed by the Federal Coal Mine Health and Safety Act of 1969. Site choice and preparation methods are clearly defined by the act. Basically, the act specifies that coal cleaning wastes are to be discarded on an impermeable layer of clay, crushed refuse, or some other suitable material, and that successive additions of waste be compacted as they are added to the dump. Erosion stability of a completed refuse disposal area is provided by grading, followed by the addition of clay, top soil, or some other sealant. Although precautions are to be taken to direct surface and ground waters away from the disposal site, any water that does pass through the site must be impounded and treated, if necessary.

2.3 COAL COMBUSTION WASTES

The burning of coal, and the use of pollution control devices such as scrubbers and precipitators, produces large volumes of solid waste materials that need to be disposed of in environmentally compatible ways. The bulk of the residue is bottom ash formed by the nonvolatile mineral matter in the coal, and fly ash, which is a fine particulate material removed from the boiler effluents by precipitators or scrubbers. More than 60 million tons of bottom ash, fly ash and scrubber sludge are produced annually in the United States from coal combustion.[8] There is growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination.

There is not yet federal legislation specifically addressing the disposal and reclamation of the various forms of coal combustion wastes. However, both the Federal Water Pollution Control Act (FWPCA) and The Resource Conservation and Recovery Act (RCRA) apply to coal combustion wastes, and, in effect, dictate to some extent how these w' ‿s can be disposed.

Land filling and ponding are the two most prevalent methods for disposing of coal combustion wastes.[9] Land disposal sites for ash include gullies, natural depressions, excavated areas, and depleted strip mines. One disadvantage of using land fill methods for disposing of coal ash in the southwestern region is that considerable maintenance is needed to reduce ash loses from the dump by the winds that frequent the area.

Much of the ash produced by coal combustion is discharged into ash ponds. With increasing frequency fly ash and scrubber sludge are being discharged into the same pond.[9] In these ponds the solids are allowed to settle, and the water is decanted off into holding ponds or recycled for process use.

About 4×10^3 acre-ft of land are required for the disposal of the 5×10^6 tons of ash that accumulate in the lifetime of a 1000 MWe coal-fired power plant.[9] If scrubber sludge is also ponded in the same area, land requirements increase disproportionately due to the relatively large volume occupied by the sludge/ash mixtures.[9]

The reclamation of ash and sludge ponds is tricky business due to high amounts of residual water that these wastes retain. Often it is necessary to add cement, thickeners or stabilizing agents to the dried solids before reclamation can proceed.[9,10] Frequently stabilizing agents are added directly to the sludges before ponding, thus alleviating the need to rework the material during reclamation. The final stages of ash and sludge pond reclamation include compacting the dried stabilized solids, adding top soil and establishing vegetation to reduce surface erodibility.

The control of contaminated leachates and seepages from disposal ponds for fly ash and scrubber sludge represents, perhaps, the most significant environmental problem facing the southwestern coal and utilities industries. Many trace contaminants that are present in the fly ash or sludge can be mobilized by the waters present in the ponds.[9,10] The transport of contaminants from the disposal ponds into shallow or deep aquifers could result in degradation of the quality of these waters. Frequently, ash and sludge disposal areas are lined with impermeable materials to reduce the loss of water from them.[9,10] Nonetheless, careful monitoring of the surface and subsurface effluents from disposal ponds is a necessity in any well planned disposal and reclamation scheme for coal combustion wastes.

3.0 DISPOSAL AND RECLAMATION OF URANIUM MINING AND MILLING WASTES

In addition to coal, the southwestern region of the United States is blessed with an abundance of uranium ore. In fact, about 50% of our current national production of uranium concentrate comes from the San Juan Basin.[11] The uranium contents of the ores of the region are quite low (usually about 0.2%)[12] hence, a relatively large volume of waste material is produced by the uranium mining and milling industries compared to most other primary minerals extraction processes.

Precluding the possible disposal of reactor wastes in southwestern sites, the major types of wastes and effluents produced by the uranium industry in the region are depicted in Fig. 2. There are many analogies between the disposal and reclamation of coal mine and combustion wastes and uranium mining and milling wastes; however, the mobile radioactive and nonradioactive components in many uranium wastes pose a far greater potential for environmental harm than do most coal wastes, dictating that much more care and judgement be exercised in disposing of uranium industry wastes.

3.1 URANIUM MINING WASTES

There are three forms of mining practiced by the uranium industry: open pit, underground, and in situ leach mining. Most of the uranium ore in the Southwest is extracted either by underground or open pit mining.[13] Nationally, about 2% of the total uranium concentrate produced results from in situ leach mining, although this form of mining is likely to become more prevalent as dwindling resources force the exploitation of lower grade ores.

Underground mining of uranium ore produces many of the same types of waste materials as does the mining of coal. These include both mine spoils and mine drainage. Mine wastes (rock and soil) are generated while gaining access to the ore bearing strata, and associated rock and lower grade ores are removed as waste during the development of the mine. Often groundwater intrudes into the mining area and mine dewatering is required. The volumes of water pumped from active underground uranium mines vary between 20 and 4000 gal/min.[14] The quality of these water discharges is variable, but sometimes treatment may be needed to reduce contaminant levels, or contaminated water is ponded and evaporated.

The solid wastes or spoils produced by underground mining of uranium ore is usually discarded in convenient nearby disposal sites. Uranium mine spoils and ores are generally not considered to be highly hazardous materials; however, there are documented instances where the contaminated drainages from surface accumulations of these materials have caused severe environmental damage to plants and animals.[15]

Mine water from underground uranium mines is usually pumped into surface drainage channels or into evaporation ponds. Some mine water is also used as process water for mining and milling operations. Where the volumes of water involved are very large, care must be exercised in disposing of them. Seepage from mine water holding ponds can pass through tailings or mine spoil disposal sites, picking up contaminants from these sources, and transporting these contaminants into the environment.

In some parts of the Grants Mineral Belt, mine dewatering has been shown to result in degradation to the quality of aquifers in the area.[16] This was due to the acute drawdown of the aquifer volume and subsequent increases in the salt contents of the water. Such consequences of mine dewatering activities may dictate in the future that mine waters be re-injected back into the strata in which they originated.

Open pit mining of uranium ore is practiced where the ore deposits are located relatively near the surface, usually at depths of less than 500 ft.[17] In a fashion similar to coal mining, overburden is removed with front end loaders, and scrapers. Additional spoils are produced during the mining operation when low grade ores are discarded or stored, or additional over-burden must be removed to expose ore pockets. Water encountered during the open pit mining of uranium is either diverted away from the mining site or is pumped to the surface and released or impounded. Here too, aquifer disruption and loss of ground water quality are difficult problems to circumvent.

There are no federal laws pertaining specifically to mine spoils or reclamation following either the strip or underground mining of uranium ore. The recently enacted Uranium Mill Tailings Radiation Control Act (UMTCA) does instruct EPA and NRC to report to Congress by 1980 concerning the locations and potential environmental hazards of uranium mine wastes, along with recommendations to eliminate these hazards. For the time being FWPCA and RCRA provide the major guidelines for the dipsosal and reclamation of these wastes. Reclamation practices for both underground and open pit mine wastes produced by uranium extraction are similar to these employed for coal mine wastes.

In many instances, it is not practical to mine certain uranium ores, due to the inaccessability of the deposits or to the low quality of the ore. Such deposits may instead be exploited by in situ leaching techniques.[18] In situ leach mining involves the pumping of chemical leach solutions into the ore deposit through an injection well, forcing the leachate through the ore to dissolve or mobilize the uranium compounds, and collecting the pregnant leach solutions at a series of recovery wells. The uranium-bearing solutions are then processed at the surface to recover the uranium.

In situ leach mining is advantageous in that it produces very small amounts of waste materials or aqueous effluents to be disposed and reclaimed. However, these apparent advantages may be more than offset by the environmental problems caused by the escape of the chemical leach solutions into subsurface water systems. Unfortunately, even the best efforts at geologic mapping cannot result in the total assurance that a leach mining site is hydrologically isolated from its surroundings.

3.2 URANIUM MILLING WASTES

Uranium milling is the process in which crushed and powdered uranium ores are subjected to a series of chemical leaching and extraction steps to remove the minute amount of uranium from the ore. These chemical processing steps partially break down the structure of the ore matrix, thereby releasing the uranium contained within. As mentioned earlier, more than 99% of the contents of the uranium ore are eventually discarded as mill wastes.
One very important consequence of the milling operation is that it also

mobilizes other potentially harmful components in the ore (such as toxic trace elements or other radioactive substances) that are released as wastes i tailings disposal sites. In addition mill tailings also contain small amounts of chemicals and solvents used in the milling processes.

Tailings are discharged from uranium mills in the form of aqueous slurries. Typical mill tailings slurries contain water, sand, silt and various slimes. The slurries are pumped into impoundments where the solids settle out and the remaining water is decanted into evaporating ponds, or is recycled back into the mill. However, seepage or overflow from tailings ponds or holding ponds often escapes into the environment. When this happens there is the strong likelihood that these waters will carry undesirable quantities of radioactive and nonradioactive contaminants with them.[19,20]

Until recently the legal basis for regulating the disposal and reclamation of uranium mill wastes was quite confusing. NRC (or individual states in agreement with NRC) held licensing authority over active tailings disposal operations, but this authority terminated when the license was withdrawn at the cessation of the mill operation. The responsibility for inactive tailing disposal areas was left piecemeal up to the individual states. In late 1978, Congress passed UMTCA, which directs that NRC provide licensing authority over both active and inactive mill tailings disposal sites. EPA is charged by the act with developing standards for tailings areas, and DOE is responsib for the development of control and reclamation methods for both active and inactive disposal areas.

Environmentally, mill tailings disposal ites are particularly troublesome because they can be the source of both atmospheric and water-borne contaminants.[19,20] Radon, a radioactive gas, is produced by radioactive decay within the tailings materials, and may be emitted to the atmosphere if precautions are not taken to seal the surface of the tailing pile.[19] In addition, as alluded to earlier, the large volumes of contaminated water in or near tailings dump sites can seep or discharge into surface or ground-water systems. Thus, the disposal and reclamations of uranium mill tailings must provide for the containment of radon gas, the containment of aqueous solutions, and long-term resistance to erosion.

Past practices, where mill tailings were discarded without much regard to environmental consequences, are no longer acceptable. Although the details of current mill tailings disposal and reclamation strategies will depend both on the nature of the disposal site and the volume of the materials involved, several key components will be present in each.[2] In the future, mill tailings will more than likely be deposited into impoundments or settling ponds that are lined with an impermeable layer of rock, clay or other stable material. Frequently, stabilizing and floccing agents will be used to more efficiently promote dewatering, and to assure the stability of the dried tailing solids. All waste water will be recycled, evaporated or treated prior to release. Upon completion of a disposal site, the entire site will be capped with another impermeable layer of clay, asphalt or concrete to retain radon and promote stability. Finally, the capping agent may be covered with soil and plant growth reestablished.

4.0 SUMMARY

The types of solid wastes and effluents produced by the southwestern coal and uranium mining and milling industries were considered, and the current methods for the disposal and reclamation of these materials were discussed. The major means of disposing of the solid wastes from both industries is by land fill or in some instances ponding. Sludges or aqueous wastes are normally discharged into settling and evaporative ponds. Basic reclamation measures for nearly all coal and uranium waste disposal sites include solids stabilization, compacting, grading, soil preparation and revegetation. Impermeable liners and caps are beginning to be applied to disposal sites for some of the more harmful coal and uranium waste materials.

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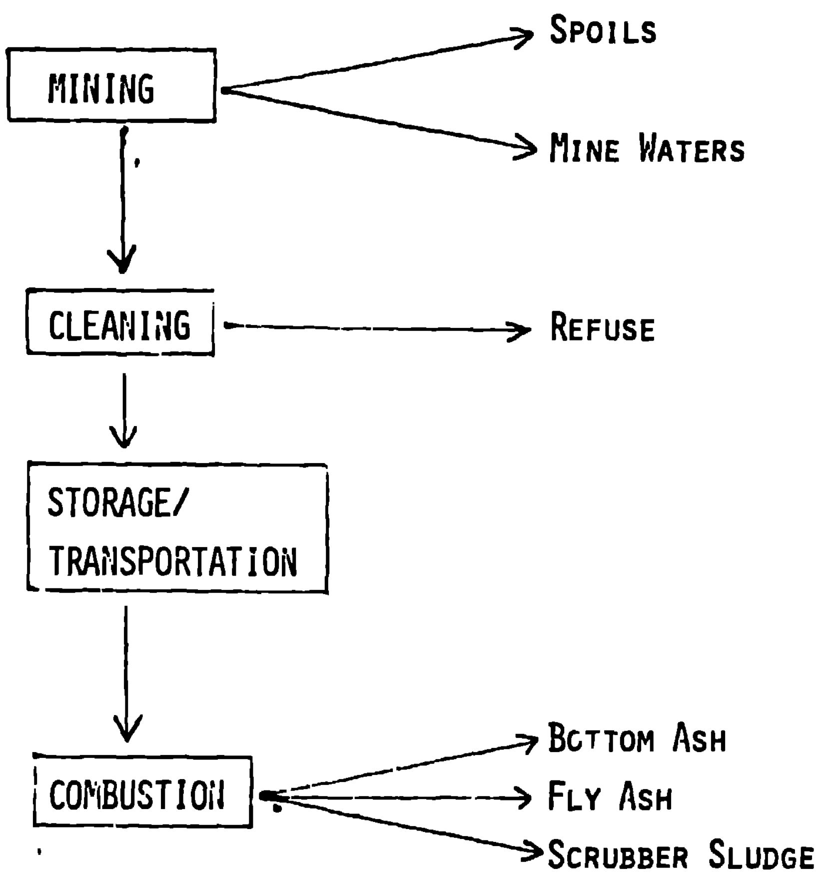

Fig. 1. Wastes produced by coal mining and combustion.

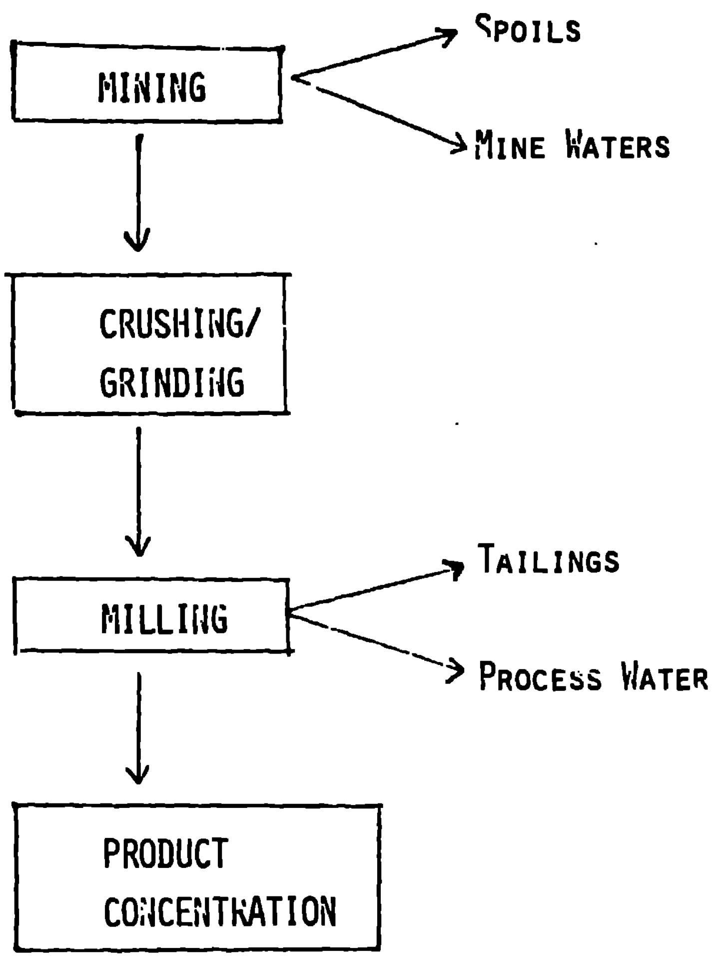

Fig. 2. Wastes produced by uranium mining and milling.

GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2015

HOUSE BILL 630
RATIFIED BILL

A BILL TO BE ENTITLED

AN ACT TO (1) REQUIRE A COAL COMBUSTION RESIDUALS IMPOUNDMENT OWNER TO PROVIDE PERMANENT ALTERNATIVE WATER SUPPLIES FOR RESIDENTS IN AREAS SURROUNDING COAL COMBUSTION RESIDUALS SURFACE IMPOUNDMENTS; (2) REPEAL STATUTORY PROVISIONS RELATED TO THE COAL ASH MANAGEMENT COMMISSION; (3) MODIFY THE CLOSURE REQUIREMENTS FOR COAL COMBUSTION RESIDUALS SURFACE IMPOUNDMENTS UNDER THE COAL ASH MANAGEMENT ACT OF 2014; AND (4) MODIFY APPOINTMENTS TO THE MINING COMMISSION AND THE OIL AND GAS COMMISSION.

The General Assembly of North Carolina enacts:

SECTION 1. Part 2I of Article 9 of Chapter 130A of the General Statutes reads as rewritten:

"Part 2I. Coal Ash Management.

"Subpart 1. Short Title, Definitions, and General Provisions.

"**§ 130A-309.200. Title.**

This Part may be cited as the "Coal Ash Management Act of 2014."

"**§ 130A-309.201. Definitions.**

Unless a different meaning is required by the context, the definitions of G.S. 130A-290 and the following definitions apply throughout this Part:

(1) "Beneficial and beneficial use" means projects promoting public health and environmental protection, offering equivalent success relative to other alternatives, and preserving natural resources.

(2) "Boiler slag" means the molten bottom ash collected at the base of slag tap and cyclone type furnaces that is quenched with water. It is made up of hard, black, angular particles that have a smooth, glassy appearance.

(3) "Bottom ash" means the agglomerated, angular ash particles formed in pulverized coal furnaces that are too large to be carried in the flue gases and collect on the furnace walls or fall through open grates to an ash hopper at the bottom of the furnace.

(4) "Coal combustion products" it means fly ash, bottom ash, boiler slag, or flue gas desulfurization materials that are beneficially used, including use for structural fill.

(5) "Coal combustion residuals" has the same meaning as defined in G.S. 130A-290.

(6) "Coal combustion residuals surface impoundment" means a topographic depression, excavation, or diked area that is (i) primarily formed from earthen materials; (ii) without a base liner approved for use by Article 9 of Chapter 130A of the General Statutes or rules adopted thereunder for a combustion products landfill or coal combustion residuals landfill, industrial landfill, or municipal solid waste landfill; and (iii) designed to hold accumulated coal combustion residuals in the form of liquid wastes, wastes containing free liquids, or sludges, and that is not backfilled or otherwise covered during periods of deposition. "Coal combustion residuals surface impoundment" shall only include impoundments owned by a public utility,

as defined in G.S. 62-3. "Coal combustion residuals surface impoundment" includes all of the following:

a. An impoundment that is dry due to the deposited liquid having evaporated, volatilized, or leached.
b. An impoundment that is wet with exposed liquid.
c. Lagoons, ponds, aeration pits, settling ponds, tailings ponds, and sludge pits, when these structures are designed to hold accumulated coal combustion residuals.
d. A coal combustion residuals surface impoundment that has been covered with soil or other material after the final deposition of coal combustion residuals at the impoundment.

~~(7) "Commission" means the Coal Ash Management Commission.~~

(8) "Flue gas desulfurization material" means the material produced through a process used to reduce sulfur dioxide emissions from the exhaust gas system of a coal-fired boiler. The physical nature of these materials varies from a wet sludge to a dry powdered material, depending on the process, and their composition comprises either sulfites, sulfates, or a mixture thereof.

(9) "Fly ash" means the very fine, powdery material, composed mostly of silica with nearly all particles spherical in shape, which is a product of burning finely ground coal in a boiler to produce electricity and is removed from the plant exhaust gases by air emission control devices.

(10) "Minerals" means soil, clay, coal, phosphate, metallic ore, and any other solid material or substance of commercial value found in natural deposits on or in the earth.

(11) "Open pit mine" means an excavation made at the surface of the ground for the purpose of extracting minerals, inorganic and organic, from their natural deposits, which excavation is open to the surface.

(12) "Owner" or "owner of a coal combustion residuals surface impoundment" means a public utility, as defined in G.S. 62-3, that owns a coal combustion residuals surface impoundment.

(13) "Receptor" means any human, plant, animal, or structure which is, or has the potential to be, affected by the release or migration of contaminants. Any well constructed for the purpose of monitoring groundwater and contaminant concentrations shall not be considered a receptor.

(14) "Structural fill" means an engineered fill with a projected beneficial end use constructed using coal combustion products that are properly placed and compacted. For purposes of this Part, the term includes fill used to reclaim open pit mines and for embankments, greenscapes, foundations, construction foundations, and for bases or sub-bases under a structure or a footprint of a paved road, parking lot, sidewalk, walkway, or similar structure.

(15) "Use or reuse of coal combustion products" means the procedure whereby coal combustion products are directly used as either of the following:

a. As an ingredient in an industrial process to make a product, unless distinct components of the coal combustion products are recovered as separate end products.
b. In a function or application as an effective substitute for a commercial product or natural resource.

"**~~§ 130A-309.202. (Repealed effective June 30, 2030) Coal Ash Management Commission.~~**

~~(a) Creation. – In recognition of the complexity and magnitude of the issues associated with the management of coal combustion residuals and the proper closure and remediation of coal combustion residuals surface impoundments, the Coal Ash Management Commission is hereby established.~~

~~(b) Membership. – The Commission shall consist of nine members as follows:~~

~~(1) One appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in accordance with G.S. 120-121 who shall at the time of appointment be a resident of the State.~~

~~(2) One appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in accordance with G.S. 120-121 who shall at the time of appointment have special training or scientific expertise~~

~~in waste management, including solid waste disposal, hauling, or beneficial use.~~

~~(3) One appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in accordance with G.S. 120-121 who shall at the time of appointment be a licensed physician or a person with experience in public health.~~

~~(4) One appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in accordance with G.S. 120-121 who shall at the time of appointment be a member of a nongovernmental conservation interest.~~

~~(5) One appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in accordance with G.S. 120-121 who shall at the time of appointment have special training or scientific expertise in waste management, including solid waste disposal, hauling, or beneficial use, or is a representative of or on the faculty of a State college or university that conducts coal ash research.~~

~~(6) One appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in accordance with G.S. 120-121 who shall at the time of appointment be a representative of an electric membership corporation organized under Article 2 of Chapter 117 of the General Statutes and have a background in power supply resource planning and engineering.~~

~~(7) One appointed by the Governor who shall at the time of appointment have experience in economic development.~~

~~(8) One appointed by the Governor who shall at the time of appointment have expertise in determining and evaluating the costs associated with electricity generation and establishing the rates associated with electricity consumption.~~

~~(9) One appointed by the Governor who shall at the time of appointment be a person with experience in science or engineering in the manufacturing sector.~~

~~(c) Chair. – The Governor shall appoint the Chair of the Commission from among the Commission's members, and that person shall serve at the pleasure of the Governor. The Chair shall serve two-year terms. The Governor shall make:~~

~~(1) The initial appointment of the Chair no later than October 1, 2014. If the initial appointment is not made by that date, the Chair shall be elected by a vote of the membership; and~~

~~(2) Appointments of a subsequent Chair, including appointments to fill a vacancy of the Chair created by resignation, dismissal, death, or disability of the Chair, no later than 30 days after the last day of the previous Chair's term. If an appointment of a subsequent Chair is not made by that date, the Chair shall be elected by a vote of the membership.~~

~~(d) Vacancies. – Any appointment to fill a vacancy on the Commission created by the resignation, dismissal, death, or disability of a member shall be for the balance of the unexpired term. The Governor may reappoint a gubernatorial appointee of the Commission to an additional term if, at the time of the reappointment, the member qualifies for membership on the Commission under subdivisions (7) through (9) of subsection (b) of this section. Appointments by the General Assembly shall be made in accordance with G.S. 120-121, and vacancies in those appointments shall be filled in accordance with G.S. 120-122.~~

~~(e) Removal. – The Governor shall have the power to remove any member of the Commission from office for misfeasance, malfeasance, or nonfeasance in accordance with the provisions of G.S. 143B-13 of the Executive Organization Act of 1973.~~

~~(f) Powers and Duties. – The Commission shall have all of the following powers and duties:~~

~~(1) To review and approve the classification of coal combustion residuals surface impoundments required by G.S. 130A-309.213.~~

~~(2) To review and approve Coal Combustion Residuals Surface Impoundment Closure Plans as provided in G.S. 130A-309.214.~~

~~(3) To review and make recommendations on the provisions of this Part and other statutes and rules related to the management of coal combustion residuals.~~

~~(4) To undertake any additional studies as requested by the General Assembly.~~

~~(g) Reimbursement. – The members of the Commission shall receive per diem and necessary travel and subsistence expenses in accordance with the provisions of G.S. 138-5.~~

~~(h) Quorum. – Five members of the Commission shall constitute a quorum for the transaction of business.~~

~~(i) Staff. – The Commission is authorized and empowered to employ staff as the Commission may determine to be necessary for the proper discharge of the Commission's duties and responsibilities. The Chair of the Commission shall organize and direct the work of the Commission staff. The salaries and compensation of all such personnel shall be fixed in the manner provided by law for fixing and regulating salaries and compensation by other State agencies. The Chair, within allowed budgetary limits and as allowed by law, shall authorize and approve travel, subsistence, and related expenses of such personnel incurred while traveling on official business. All State agencies, including the constituent institutions of The University of North Carolina, shall provide information and support to the Commission upon request.~~

~~(j) Repealed by Session Laws 2015-9, s. 1.1, effective April 27, 2015.~~

~~(k) Covered Persons; Conflicts of Interest; Disclosure. – All members of the Commission are covered persons for the purposes of Chapter 138A of the General Statutes, the State Government Ethics Act. As covered persons, members of the Commission shall comply with the applicable requirements of the State Government Ethics Act, including mandatory training, the public disclosure of economic interests, and ethical standards for covered persons. Members of the Commission shall comply with the provisions of the State Government Ethics Act to avoid conflicts of interest. The Governor may require additional disclosure of potential conflicts of interest by members. The Governor may promulgate criteria regarding conflicts of interest and disclosure thereof for determining the eligibility of persons under this subsection, giving due regard to the requirements of federal legislation, and, for this purpose, may promulgate rules, regulations, or guidelines in conformance with those established by any federal agency interpreting and applying provisions of federal law.~~

~~(l) Meetings. – The Commission shall meet at least once every two months and may hold special meetings at any time and place within the State at the call of the Chair or upon the written request of at least five members.~~

~~(m) Reports. – The Commission shall submit quarterly written reports as to its operation, activities, programs, and progress to the Environmental Review Commission. The Commission shall supplement the written reports required by this subsection with additional written and oral reports as may be requested by the Environmental Review Commission. The Commission shall submit the written reports required by this subsection whether or not the General Assembly is in session at the time the report is due.~~

~~(n) Administrative Location; Independence. – The Commission shall be administratively located in the Division of Emergency Management of the Department of Public Safety. The Commission shall exercise all of its powers and duties independently and shall not be subject to the supervision, direction, or control of the Division or Department.~~

~~(o) Terms of Members. – Members of the Commission shall serve terms of six years, beginning effective July 1 of the year of appointment.~~

"§ 130A-309.203. Expedited permit review.

(a) The Department shall act as expeditiously as practicable, but no later than the deadlines established under subsection (b) of this section, except in compliance with subsection (c) of this section, to issue all permits necessary to conduct activities required by this Part.

(b) Notwithstanding G.S. 130A-295.8(e), the Department shall determine whether an application for any permit necessary to conduct activities required by this Part is complete within 30 days after the Department receives the application for the permit. A determination of completeness means that the application includes all required components but does not mean that the required components provide all of the information that is required for the Department to make a decision on the application. If the Department determines that an application is not complete, the Department shall notify the applicant of the components needed to complete the application. An applicant may submit additional information to the Department to cure the deficiencies in the application. The Department shall make a final determination as to whether the application is complete within the later of (i) 30 days after the Department receives the application for the permit less the number of days that the applicant uses to provide the additional information or (ii) 10 days after the Department receives the additional information from the applicant. The Department shall issue a draft permit decision on an application for a permit within 90 days after the Department determines that the application is complete. The Department shall hold a public hearing and accept written comment on the draft permit decision for a period of not less than 30 or more than 60 days after the Department issues a draft permit decision. The Department shall issue a final permit decision on an application for a permit within 60 days after the comment period on the draft permit decision closes. If the Department fails to act within any time period set out in this subsection, the applicant may treat the failure to act as a denial of the permit and may challenge the denial as provided in Chapter 150B of the General Statutes.

(c) If the Department finds that compliance with the deadlines established under subsection (b) of this section would result in insufficient review of a permit application that would pose a risk to public health, safety, and welfare; the environment; or natural resources, the applicable deadline shall be waived for the application as necessary to allow for adequate review. If a deadline is waived pursuant to this subsection, the Secretary shall issue a written declaration, including findings of fact, documenting the need for the waiver.

(d) Notwithstanding any other provision of this section or any other provision of law, the Department shall either issue or deny a permit required for dewatering of a retired impoundment within 90 days of receipt of a completed application, in such a form and including such information as the Department may prescribe, for the dewatering activities. The Department shall accept written comment on a draft permit decision for a period of not less than 30 days or more than 60 days prior to issuance or denial of such a permit. If the Department fails to act within any time period set out in this subsection, the applicant may treat the failure to act as a denial of the permit and may challenge the denial as provided in Chapter 150B of the General Statutes.

"§ 130A-309.204. Reports.

(a) The Department shall submit quarterly written reports to the Environmental Review Commission ~~and the Coal Ash Management Commission~~ on its operations, activities, programs, and progress with respect to its obligations under this Part concerning all coal combustion residuals surface impoundments. At a minimum, the report shall include information concerning the status of assessment, corrective action, prioritization, and closure for each coal combustion residuals surface impoundment and information on costs connected therewith. The report shall include an executive summary of each annual Groundwater Protection and Restoration Report submitted to the Department by the operator of any coal combustion residuals surface impoundments pursuant to G.S. 130A-309.211(d) and a summary of all groundwater sampling, protection, and restoration activities related to the impoundment for the preceding year. The report shall also include an executive summary of each annual Surface Water Protection and Restoration Report submitted to the Department by the operator of any coal combustion residuals surface impoundments pursuant to G.S. 130A-309.212(e) and a summary of all surface water sampling, protection, and restoration activities related to the impoundment for the preceding year, including the status of the identification, assessment, and correction of unpermitted discharges from coal combustion residuals surface impoundments to the surface waters of the State. The Department shall supplement the written reports required by this subsection with additional written and oral reports as may be requested by the Environmental Review Commission. The Department shall submit the written reports required by this subsection whether or not the General Assembly is in session at the time the report is due.

(b) On or before October 1 of each year, the Department shall report to each member of the General Assembly who has a coal combustion residuals surface impoundment in the member's district. This report shall include the location of each impoundment in the member's district, the amount of coal combustion residuals known or believed to be located in the impoundment, the last action taken at the impoundment, and the date of that last action.

(c) On or before October 1 of each year, a public utility generating coal combustion residuals and coal combustion products shall submit an annual summary to the Department. The annual summary shall be for the period of July 1 through June 30 and shall include all of the following:

(1) The volume of coal combustion residuals and products produced.

(2) The volume of coal combustion residuals disposed.
(3) The volume of coal combustion products used in structural fill projects.
(4) The volume of coal combustion products beneficially used, other than for structural fill.

"§ 130A-309.205. Local ordinances regulating management of coal combustion residuals and coal combustion products invalid; petition to preempt local ordinance.

(a) It is the intent of the General Assembly to maintain a uniform system for the management of coal combustion residuals and coal combustion products, including matters of disposal and beneficial use, and to place limitations upon the exercise by all units of local government in North Carolina of the power to regulate the management of coal combustion residuals and coal combustion products by means of ordinances, property restrictions, zoning regulations, or otherwise. Notwithstanding any authority granted to counties, municipalities, or other local authorities to adopt local ordinances, including those imposing taxes, fees, or charges or regulating health, environment, or land use, all provisions of local ordinances, including those regulating land use, adopted by counties, municipalities, or other local authorities that regulate or have the effect of regulating the management of coal combustion residuals and coal combustion products, including regulation of carbon burn-out plants, within the jurisdiction of a local government are invalidated and unenforceable, to the extent necessary to effectuate the purposes of this Part, that do the following:

(1) Place any restriction or condition not placed by this Part upon management of coal combustion residuals or coal combustion products within any county, city, or other political subdivision.
(2) Conflict or are in any manner inconsistent with the provisions of this Part.

(a1) As used in this section, "Commission" means the Environmental Management Commission.

(b) If a local zoning or land-use ordinance imposes requirements, restrictions, or conditions that are generally applicable to development, including, but not limited to, setback, buffer, and stormwater requirements, and coal combustion residuals and coal combustion products would be regulated under the ordinance of general applicability, the operator of the proposed activities may petition the Environmental Management Commission to review the matter. After receipt of a petition, the Commission shall hold a hearing in accordance with the procedures in subsection (c) of this section and shall determine whether or to what extent to preempt the local ordinance to allow for the management of coal combustion residuals and coal combustion products.

(c) When a petition described in subsection (b) of this section has been filed with the Environmental Management Commission, the Commission shall hold a public hearing to consider the petition. The public hearing shall be held in the affected locality within 60 days after receipt of the petition by the Commission. The Commission shall give notice of the public hearing by both of the following means:

(1) Publication in a newspaper or newspapers having general circulation in the county or counties where the activities are to be conducted, once a week for three consecutive weeks, the first notice appearing at least 30 days prior to the scheduled date of the hearing.
(2) First-class mail to persons who have requested notice. The Commission shall maintain a mailing list of persons who request notice in advance of the hearing pursuant to this section. Notice by mail shall be complete upon deposit of a copy of the notice in a postage-paid wrapper addressed to the person to be notified at the address that appears on the mailing list maintained by the Commission in a post office or official depository under the exclusive care and custody of the United States Postal Service.

(d) Any interested person may appear before the Environmental Management Commission at the hearing to offer testimony. In addition to testimony before the Commission, any interested person may submit written evidence to the Commission for the Commission's consideration. At least 20 days shall be allowed for receipt of written comment following the hearing.

(e) A local zoning or land-use ordinance is presumed to be valid and enforceable to the extent the zoning or land-use ordinance imposes requirements, restrictions, or conditions that are generally applicable to development, including, but not limited to, setback, buffer, and stormwater requirements, unless the Environmental Management Commission makes a finding of fact to the contrary. The Commission shall determine whether or to what extent to preempt local ordinances so as to allow the project involving management of coal combustion residuals and coal combustion products no later than 60 days after conclusion of the hearing. The Commission shall preempt a local ordinance only if the Commission makes all of the following findings:

(1) That there is a local ordinance that would regulate the management of coal combustion residuals and coal combustion products.

(2) That all legally required State and federal permits or approvals have been issued by the appropriate State and federal agencies or that all State and federal permit requirements have been satisfied and that the permits or approvals have been denied or withheld only because of the local ordinance.

(3) That local citizens and elected officials have had adequate opportunity to participate in the permitting process.

(4) That the project involving management of coal combustion residuals and coal combustion products will not pose an unreasonable health or environmental risk to the surrounding locality and that the operator has taken or consented to take reasonable measures to avoid or manage foreseeable risks and to comply to the maximum feasible extent with applicable local ordinances.

(f) If the Environmental Management Commission does not make all of the findings under subsection (e) of this section, the Commission shall not preempt the challenged local ordinance. The Commission's decision shall be in writing and shall identify the evidence submitted to the Commission plus any additional evidence used in arriving at the decision.

(g) The decision of the Environmental Management Commission shall be final, unless a party to the action files a written appeal under Article 3 of Chapter 150B of the General Statutes, as modified by this section, within 30 days of the date of the decision. The record on appeal shall consist of all materials and information submitted to or considered by the Commission, the Commission's written decision, a complete transcript of the hearing, the specific findings required by subsection (e) of this section, and any minority positions on the specific findings required by subsection (e) of this section. The scope of judicial review shall be as set forth in G.S. 150B-51, except as this subsection provides regarding the record on appeal.

(h) If the court reverses or modifies the decision of the Environmental Management Commission, the judge shall set out in writing, which writing shall become part of the record, the reasons for the reversal or modification.

(i) In computing any period of time prescribed or allowed by the procedure in this section, the provisions of Rule 6(a) of the Rules of Civil Procedure, G.S. 1A-1, shall apply.

"§ 130A-309.206. Federal preemption; severability.

The provisions of this Part shall be severable, and if any phrase, clause, sentence, or provision is declared to be unconstitutional or otherwise invalid or is preempted by federal law or regulation, the validity of the remainder of this Part shall not be affected thereby.

"§ 130A-309.207. General rule making for Part.

The Environmental Management Commission shall adopt rules as necessary to implement the provisions of the Part. Such rules shall be exempt from the requirements of G.S. 150B-19.3.

"§ 130A-309.208: Reserved for future codification purposes.

"§ 130A-309.209: Reserved for future codification purposes.

"Subpart 2. Management of Coal Ash Residuals; Closure of Coal Ash Impoundments.

"§ 130A-309.210. Generation, disposal, and use of coal combustion residuals.

(a) On or after October 1, 2014, the construction of new and expansion of existing coal combustion residuals surface impoundments is prohibited.

(b) On or after October 1, 2014, the disposal of coal combustion residuals into a coal combustion residuals surface impoundment at an electric generating facility where the coal-fired generating units are no longer producing coal combustion residuals is prohibited.

(c) On or after December 31, 2018, the discharge of stormwater into a coal combustion surface impoundment at an electric generating facility where the coal-fired generating units are no longer producing coal combustion residuals is prohibited.

(d) On or after December 31, 2019, the discharge of stormwater into a coal combustion surface impoundment at an electric generating facility where the coal-fired generating units are actively producing coal combustion residuals is prohibited.

(e) On or before December 31, 2018, all electric generating facilities owned by a public utility shall convert to the disposal of "dry" fly ash or the facility shall be retired. For purposes of this subsection, the term "dry" means coal combustion residuals that are not in the form of liquid wastes, wastes containing free liquids, or sludges.

(f) On or before December 31, 2019, all electric generating facilities owned by a public utility shall convert to the disposal of "dry" bottom ash or the facility shall be retired. For purposes of this subsection, the term "dry" means coal combustion residuals that are not in the form of liquid wastes, wastes containing free liquids, or sludges.

"§ 130A-309.211. Groundwater assessment and corrective action; drinking water supply well survey and provision of alternate water supply; reporting.

(a) Groundwater Assessment of Coal Combustion Residuals Surface Impoundments. – The owner of a coal combustion residuals surface impoundment shall conduct groundwater monitoring and assessment as provided in this subsection. The requirements for groundwater monitoring and assessment set out in this subsection are in addition to any other groundwater monitoring and assessment requirements applicable to the owners of coal combustion residuals surface impoundments:

(1) No later than December 31, 2014, the owner of a coal combustion residuals surface impoundment shall submit a proposed Groundwater Assessment Plan for the impoundment to the Department for its review and approval. The Groundwater Assessment Plan shall, at a minimum, provide for all of the following:
   a. A description of all receptors and significant exposure pathways.
   b. An assessment of the horizontal and vertical extent of soil and groundwater contamination for all contaminants confirmed to be present in groundwater in exceedance of groundwater quality standards.
   c. A description of all significant factors affecting movement and transport of contaminants.
   d. A description of the geological and hydrogeological features influencing the chemical and physical character of the contaminants.
   e. A schedule for continued groundwater monitoring.
   f. Any other information related to groundwater assessment required by the Department.

(2) The Department shall approve the Groundwater Assessment Plan if it determines that the Plan complies with the requirements of this subsection and will be sufficient to protect public health, safety, and welfare; the environment; and natural resources.

(3) No later than 10 days from approval of the Groundwater Assessment Plan, the owner shall begin implementation of the Plan.

(4) No later than 180 days from approval of the Groundwater Assessment Plan, the owner shall submit a Groundwater Assessment Report to the Department. The Report shall describe all exceedances of groundwater quality standards associated with the impoundment.

(b) Corrective Action for the Restoration of Groundwater Quality. – The owner of a coal combustion residuals surface impoundment shall implement corrective action for the restoration of groundwater quality as provided in this subsection. The requirements for corrective action for the restoration of groundwater quality set out in this subsection are in addition to any other corrective action for the restoration of groundwater quality requirements applicable to the owners of coal combustion residuals surface impoundments:

(1) No later than 90 days from submission of the Groundwater Assessment Report required by subsection (a) of this section, or a time frame otherwise approved by the Department not to exceed 180 days from submission of the Groundwater Assessment Report, the owner of the coal combustion residuals surface impoundment shall submit a proposed Groundwater Corrective Action Plan to the Department for its review and approval. The Groundwater Corrective Action Plan shall provide for the restoration of groundwater in conformance with the requirements of Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code. The Groundwater Corrective Action Plan shall include, at a minimum, all of the following:

a. A description of all exceedances of the groundwater quality standards, including any exceedances that the owner asserts are the result of natural background conditions.

b. A description of the methods for restoring groundwater in conformance with the requirements of Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code and a detailed explanation of the reasons for selecting these methods.

c. Specific plans, including engineering details, for restoring groundwater quality.

d. A schedule for implementation of the Plan.

e. A monitoring plan for evaluating the effectiveness of the proposed corrective action and detecting movement of any contaminant plumes.

f. Any other information related to groundwater assessment required by the Department.

(2) The Department shall approve the Groundwater Corrective Action Plan if it determines that the Plan complies with the requirements of this subsection and will be sufficient to protect public health, safety, and welfare; the environment; and natural resources.

(3) No later than 30 days from the approval of the Groundwater Corrective Action Plan, the owner shall begin implementation of the Plan in accordance with the Plan's schedule.

(c) Drinking Water Supply Well Survey and Provision of Alternate Water Supply. – No later than October 1, 2014, the owner of a coal combustion residuals surface impoundment shall conduct a Drinking Water Supply Well Survey that identifies all drinking water supply wells within one-half mile down-gradient from the established compliance boundary of the impoundment and submit the Survey to the Department. The Survey shall include well locations, the nature of water uses, available well construction details, and information regarding ownership of the wells. No later than December 1, 2014, the Department shall determine, based on the Survey, which drinking water supply wells the owner is required to sample and how frequently and for what period sampling is required. The Department shall require sampling for drinking water supply wells where data regarding groundwater quality and flow and depth in the area of any surveyed well provide a reasonable basis to predict that the quality of water from the surveyed well may be adversely impacted by constituents associated with the presence of the impoundment. No later than January 1, 2015, the owner shall initiate sampling and water quality analysis of the drinking water supply wells. A property owner may elect to have an independent third party selected from a laboratory certified by the Department's Wastewater/Groundwater Laboratory Certification program sample wells located on their property in lieu of sampling conducted by the owner of the coal combustion residuals surface impoundment. The owner of the coal combustion residuals surface impoundment shall pay for the reasonable costs of such sampling. Nothing in this subsection shall be construed to preclude or impair the right of any property owner to refuse such sampling of wells on their property. If the sampling and water quality analysis indicates that water from a drinking water supply well exceeds groundwater quality standards for constituents associated with the presence of the impoundment, the owner shall replace the contaminated drinking water supply well with an alternate supply of potable drinking water and an alternate supply of water that is safe for other household uses. The alternate supply of potable drinking water shall be supplied within 24 hours of the Department's determination that there is an exceedance of groundwater quality standards attributable to constituents associated with the presence of the impoundment. The alternate supply of water that is safe for other household uses shall be supplied within 30 days of the Department's determination that there is an exceedance of groundwater quality standards attributable to constituents associated with the presence of the impoundment. The requirement to replace a contaminated drinking water supply well with an alternate supply of potable drinking water and an alternate supply of water that is safe for other household uses set out in this subsection is in addition to any other requirements to replace a contaminated drinking water supply well with an alternate supply of potable drinking water or an alternate supply of water that is safe for other household uses applicable to the owners of coal combustion residuals surface impoundments.

(c1) Provision of Permanent Water Supply. – As soon as practicable, but no later than October 15, 2018, the owner of a coal combustion residuals surface impoundment shall establish permanent replacement water supplies for (i) each household that has a drinking water supply well located within a one-half mile radius from the established compliance boundary of a coal combustion residuals impoundment, and is not separated from the impoundment by the mainstem of a river, as that term is defined under G.S. 143-215.22G, or other body of water that would prevent the migration of contaminants through groundwater from the impoundment to a well and (ii) each household that has a drinking water supply well that is located in an area in which contamination resulting from constituents associated with the presence of a coal combustion residuals impoundment is expected to migrate, as demonstrated by groundwater modeling and hydrogeologic, geologic, and geotechnical investigations of the site, conducted in accordance with the requirements of G.S. 130A-309.214(a)(4), and the results of other modeling or investigations that may have been submitted pursuant to G.S. 130A-309.213(b)(4). Preference shall be given to permanent replacement water supplies by connection to public water supplies; provided that (i) a household may elect to receive a filtration system in lieu of a connection to public water supplies and (ii) if the Department determines that connection to a public water supply to a particular household would be cost-prohibitive, the Department shall authorize provision of a permanent replacement water supply to that household through installation of a filtration system. For households for which filtration systems are installed, the impoundment owner shall be responsible for periodic required maintenance of the filtration system. No later than December 15, 2016, an impoundment owner shall submit information on permanent replacement water supplies proposed to be provided to each household to the Department, including, at a minimum, the type of permanent water supply proposed; the location of the household and its proximity to the nearest connection point to a public water supply; projected cost of the permanent water supply option proposed for the household; and any proposal to connect to a public water supply. The Department shall evaluate information submitted by the impoundment owner and render a final decision to approve or disapprove the plan, including written findings of fact, no later than January 15, 2017. If disapproved, an impoundment owner shall resubmit a plan for the Department's approval within 30 days. No later than April 15, 2017, an impoundment owner shall notify all residents identified in the approved plan of their eligibility for establishment of a permanent water supply. Until such time as an impoundment owner has established a permanent water supply for each household required by this subsection, the impoundment owner shall supply the household with an alternate supply of potable drinking water and an alternate supply of water that is safe for other household uses. Nothing in this section shall be construed to (i) require an eligible household to connect to a public water supply or receive a filtration system or (ii) obviate the need for other federal, State, and local permits and approvals. All State entities and local governments shall expedite any permits and approvals required for such projects. The Department may grant an impoundment owner an extension of time, not to exceed one year, to establish permanent water supplies as required by this section, if the Department determines that it is infeasible for the impoundment owner to establish a permanent water supply for a household by October 15, 2018, based on limitations arising from local government resources, including limitations on water supply capacity and staffing limitations for permitting and construction activities.

(d) Reporting. – In addition to any other reporting required by the Department, the owner of a coal combustion residuals surface impoundment shall submit an annual Groundwater Protection and Restoration Report to the Department no later than January 31 of each year. The Report shall include a summary of all groundwater monitoring, protection, and restoration activities related to the impoundment for the preceding year, including the status of the Groundwater Assessment Plan, the Groundwater Assessment Report, the Groundwater Corrective Action Plan, the Drinking Water Supply Well Survey, and the replacement of any contaminated drinking water supply wells. ~~The owner of a coal combustion residuals surface impoundment shall also submit all information required to be submitted to the Department pursuant to this section to the Coal Ash Management Commission.~~

"§ 130A-309.212. Identification and assessment of discharges; correction of unpermitted discharges.

(a) Identification of Discharges from Coal Combustion Residuals Surface Impoundments. –

(1) The owner of a coal combustion residuals surface impoundment shall identify all discharges from the impoundment as provided in this subsection.

The requirements for identifying all discharges from an impoundment set out in this subsection are in addition to any other requirements for identifying discharges applicable to the owners of coal combustion residuals surface impoundments.

(2) No later than December 31, 2014, the owner of a coal combustion residuals surface impoundment shall submit a topographic map that identifies the location of all (i) outfalls from engineered channels designed or improved for the purpose of collecting water from the toe of the impoundment and (ii) seeps and weeps discharging from the impoundment that are not captured by engineered channels designed or improved for the purpose of collecting water from the toe of the impoundment to the Department. The topographic map shall comply with all of the following:

a. Be at a scale as required by the Department.

b. Specify the latitude and longitude of each toe drain outfall, seep, and weep.

c. Specify whether the discharge from each toe drain outfall, seep, and weep is continuous or intermittent.

d. Provide an average flow measurement of the discharge from each toe drain outfall, seep, and weep including a description of the method used to measure average flow.

e. Specify whether the discharge from each toe drain outfall, seep, and weep identified reaches the surface waters of the State. If the discharge from a toe drain outfall, seep, or weep reaches the surface waters of the State, the map shall specify the latitude and longitude of where the discharge reaches the surface waters of the State.

f. Include any other information related to the topographic map required by the Department.

(b) Assessment of Discharges from Coal Combustion Residuals Surface Impoundments to the Surface Waters of the State. – The owner of a coal combustion residuals surface impoundment shall conduct an assessment of discharges from the coal combustion residuals surface impoundment to the surface waters of the State as provided in this subsection. The requirements for assessment of discharges from the coal combustion residuals surface impoundment to the surface waters of the State set out in this subsection are in addition to any other requirements for the assessment of discharges from coal combustion residuals surface impoundments to surface waters of the State applicable to the owners of coal combustion residuals surface impoundments:

(1) No later than December 31, 2014, the owner of a coal combustion residuals surface impoundment shall submit a proposed Discharge Assessment Plan to the Department. The Discharge Assessment Plan shall include information sufficient to allow the Department to determine whether any discharge, including a discharge from a toe drain outfall, seep, or weep, has reached the surface waters of the State and has caused a violation of surface water quality standards. The Discharge Assessment Plan shall include, at a minimum, all of the following:

a. Upstream and downstream sampling locations within all channels that could potentially carry a discharge.

b. A description of the surface water quality analyses that will be performed.

c. A sampling schedule, including the frequency and duration of sampling activities.

d. Reporting requirements.

e. Any other information related to the assessment of discharges required by the Department.

(2) The Department shall approve the Discharge Assessment Plan if it determines that the Plan complies with the requirements of this subsection and will be sufficient to protect public health, safety, and welfare; the environment; and natural resources.

(3) No later than 30 days from the approval of the Discharge Assessment Plan, the owner shall begin implementation of the Plan in accordance with the Plan's schedule.

(c) Corrective Action to Prevent Unpermitted Discharges from Coal Combustion Residuals Surface Impoundments to the Surface Waters of the State. – The owner of a coal combustion residuals surface impoundment shall implement corrective action to prevent unpermitted discharges from the coal combustion residuals surface impoundment to the surface waters of the State as provided in this subsection. The requirements for corrective action to prevent unpermitted discharges from coal combustion residuals surface impoundments to the surface waters of the State set out in this subsection are in addition to any other requirements for corrective action to prevent unpermitted discharges from coal combustion residuals surface impoundments to the surface waters of the State applicable to the owners of coal combustion residuals surface impoundments:

(1) If the Department determines, based on information provided pursuant to subsection (a) or (b) of this section, that an unpermitted discharge from a coal combustion residuals surface impoundment, including an unpermitted discharge from a toe drain outfall, seep, or weep, has reached the surface waters of the State, the Department shall notify the owner of the impoundment of its determination.

(2) No later than 30 days from a notification pursuant to subdivision (1) of this subsection, the owner of the coal combustion residuals surface impoundment shall submit a proposed Unpermitted Discharge Corrective Action Plan to the Department for its review and approval. The proposed Unpermitted Discharge Corrective Action Plan shall include, at a minimum, all of the following:

a. One of the following methods of proposed corrective action:

1. Elimination of the unpermitted discharge.

2. Application for a National Pollutant Discharge Elimination System (NPDES) permit amendment pursuant to G.S. 143-215.1 and Subchapter H of Chapter 2 of Title 15A of the North Carolina Administrative Code to bring the unpermitted discharge under permit regulations.

b. A detailed explanation of the reasons for selecting the method of corrective action.

c. Specific plans, including engineering details, to prevent the unpermitted discharge.

d. A schedule for implementation of the Plan.

e. A monitoring plan for evaluating the effectiveness of the proposed corrective action.

f. Any other information related to the correction of unpermitted discharges required by the Department.

(3) The Department shall approve the Unpermitted Discharge Corrective Action Plan if it determines that the Plan complies with the requirements of this subsection and will be sufficient to protect public health, safety, and welfare; the environment; and natural resources.

(4) No later than 30 days from the approval of the Unpermitted Discharge Corrective Action Plan, the owner shall begin implementation of the Plan in accordance with the Plan's schedule.

(d) Identification of New Discharges. – No later than October 1, 2014, the owner of a coal combustion residuals surface impoundment shall submit a proposed Plan for the Identification of New Discharges to the Department for its review and approval as provided in this subsection:

(1) The proposed Plan for the Identification of New Discharges shall include, at a minimum, all of the following:

a. A procedure for routine inspection of the coal combustion residuals surface impoundment to identify indicators of potential new discharges, including toe drain outfalls, seeps, and weeps.

b. A procedure for determining whether a new discharge is actually present.

c. A procedure for notifying the Department when a new discharge is confirmed.

d. Any other information related to the identification of new discharges required by the Department.

(2) The Department shall approve the Plan for the Identification of New Discharges if it determines that the Plan complies with the requirements of this subsection and will be sufficient to protect public health, safety, and welfare; the environment; and natural resources.

(3) No later than 30 days from the approval of the Plan for the Identification of New Discharges, the owner shall begin implementation of the Plan in accordance with the Plan.

(e) Reporting. – In addition to any other reporting required by the Department, the owner of a coal combustion residuals surface impoundment shall submit an annual Surface Water Protection and Restoration Report to the Department no later than January 31 of each year. The Report shall include a summary of all surface water sampling, protection, and restoration activities related to the impoundment for the preceding year, including the status of the identification, assessment, and correction of unpermitted discharges from coal combustion residuals surface impoundments to the surface waters of the State.~~ The owner of a coal combustion residuals surface impoundment shall also submit all information required to be submitted to the Department pursuant to this section to the Coal Ash Management Commission.~~

"**§ 130A-309.213. Prioritization of coal combustion residuals surface impoundments.**

(a) As soon as practicable, but no later than December 31, 2015, the Department shall develop proposed classifications for all coal combustion residuals surface impoundments, including active and retired sites, for the purpose of closure and remediation based on these sites' risks to public health, safety, and welfare; the environment; and natural resources and shall determine a schedule for closure and required remediation that is based on the degree of risk to public health, safety, and welfare; the environment; and natural resources posed by the impoundments and that gives priority to the closure and required remediation of impoundments that pose the greatest risk. In assessing the risk, the Department shall evaluate information received pursuant to G.S. 130A-309.211 and G.S. 130A-309.212 and any other information deemed ~~relevant and, at a minimum, consider all of the following:~~relevant.

~~(1) Any hazards to public health, safety, or welfare resulting from the impoundment.~~

~~(2) The structural condition and hazard potential of the impoundment.~~

~~(3) The proximity of surface waters to the impoundment and whether any surface waters are contaminated or threatened by contamination as a result of the impoundment.~~

~~(4) Information concerning the horizontal and vertical extent of soil and groundwater contamination for all contaminants confirmed to be present in groundwater in exceedance of groundwater quality standards and all significant factors affecting contaminant transport.~~

~~(5) The location and nature of all receptors and significant exposure pathways.~~

~~(6) The geological and hydrogeological features influencing the movement and chemical and physical character of the contaminants.~~

~~(7) The amount and characteristics of coal combustion residuals in the impoundment.~~

~~(8) Whether the impoundment is located within an area subject to a 100-year flood.~~

~~(9) Any other factor the Department deems relevant to establishment of risk.~~

(b) The Department shall issue a proposed classification for each coal combustion residuals surface impoundment based upon the assessment conducted pursuant to subsection (a) of this section as high-risk, intermediate-risk, or low-risk. Within 30 days after a proposed classification has been issued, the Department shall issue a written declaration, including findings of fact, documenting the proposed classification. The Department shall provide for public participation on the proposed risk classification as follows:

(1) The Department shall make copies of the written declaration issued pursuant to this subsection available for inspection as follows:

a. A copy of the declaration shall be provided to the local health director.

b. A copy of the declaration shall be provided to the public library located in closest proximity to the site in the county or counties in which the site is located.

c. The Department shall post a copy of the declaration on the Department's Web site.

d. The Department shall place copies of the declaration in other locations so as to assure the reasonable availability thereof to the public.

(2) The Department shall give notice of the written declaration issued pursuant to this subsection as follows:

a. A notice and summary of the declaration shall be published weekly for a period of three consecutive weeks in a newspaper having general circulation in the county or counties where the site is located.

b. Notice of the written declaration shall be given by first-class mail to persons who have requested such notice. Such notice shall include a summary of the written declaration and state the locations where a copy of the written declaration is available for inspection. The Department shall maintain a mailing list of persons who request notice pursuant to this section.

c. Notice of the written declaration shall be given by electronic mail to persons who have requested such notice. Such notice shall include a summary of the written declaration and state the locations where a copy of the written declaration is available for inspection. The Department shall maintain a mailing list of persons who request notice pursuant to this section.

(3) No later than 60 days after issuance of the written declaration, the Department shall conduct a public meeting in the county or counties in which the site is located to explain the written declaration to the public. The Department shall give notice of the hearing at least 15 days prior to the date thereof by all of the following methods:

a. Publication as provided in subdivision (1) of this subsection, with first publication to occur not less than 30 days prior to the scheduled date of the hearing.

b. First-class mail to persons who have requested notice as provided in subdivision (2) of this subsection.

c. Electronic mail to persons who have requested notice as provided in subdivision (2) of this subsection.

(4) At least 30 days from the latest date on which notice is provided pursuant to subdivision (2) of this subsection shall be allowed for the receipt of written comment on the written declaration prior to issuance of a final risk classification. At least 20 days will be allowed for receipt of written comment following a hearing conducted pursuant to subdivision (3) of this subsection prior to issuance of a ~~final~~ <u>preliminary</u> risk classification.

~~(c) Within 30 days of the receipt of all written comment as required by subdivision (4) of subsection (b) of this section, the Department shall submit a proposed classification for a coal combustion residuals surface impoundment to the Coal Ash Management Commission established pursuant to G.S. 130A-309.202. The Commission shall evaluate all information submitted in accordance with this Part related to the proposed classification and any other information the Commission deems relevant. The Commission shall only approve the proposed classification if it determines that the classification was developed in accordance with this section and that the classification accurately reflects the level of risk posed by the coal combustion residuals surface impoundment. The Commission shall issue its determination in writing, including findings in support of its determination. If the Commission fails to act on a proposed classification within 60 days of receipt of the proposed classification, the proposed classification shall be deemed approved. Parties aggrieved by a final decision of the Commission pursuant to this subsection may appeal the decision as provided under Article 3 of Chapter 150B of the General Statutes.~~

(d) No later than 30 days after expiration of the deadline set forth in G.S. 130A-309.211(c1), or any applicable extension granted by the Secretary pursuant G.S. 130A-309.211(c1), the Department shall issue a final classification for each impoundment as follows:

(1) The Department shall classify an impoundment as low-risk if the impoundment owner satisfies both of the following criteria:

a. Has established permanent water supplies as required for the impoundment pursuant to G.S. 130A-309.211(c1).

b. Has rectified any deficiencies identified by, and otherwise complied with the requirements of, any dam safety order issued by the Environmental Management Commission for the impoundment pursuant to G.S. 143-215.32. No later than July 1, 2018, the Department shall conduct the annual inspection of each dam associated with a coal combustion residuals surface impoundment required for that year, to detect any deficiencies and to ascertain, at a minimum, whether the dam is sufficiently strong, maintained in good repair and operating condition, does not pose a danger to life or property, and satisfies minimum streamflow requirements. The Department shall issue written findings of fact for each inspection and present such findings to the Environmental Management Commission. If the Department detects any deficiencies, the Commission shall issue an order directing the owner of the dam to take action as may be deemed necessary by the Commission within a time limited by the order, but not later than 90 days after issuance of the order.

(2) All other impoundments shall be classified as intermediate-risk.

(e) Parties aggrieved by a final decision of the Department issued pursuant to subsection (d) of this section may appeal the decision as provided under Article 3 of Chapter 150B of the General Statutes.

"§ 130A-309.214. Closure of coal combustion residuals surface impoundments.

(a) An owner of a coal combustion residuals surface impoundment shall submit a proposed Coal Combustion Residuals Surface Impoundment Closure Plan for the Department's approval. If corrective action to restore groundwater has not been completed pursuant to the requirements of G.S. 130A-309.211(b), the proposed closure plan shall include provisions for completion of activities to restore groundwater in conformance with the requirements of Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code. In addition, the following requirements, at a minimum, shall apply to such plans:

(1) High-risk impoundments shall be closed as soon as practicable, but no later than December 31, 2019. A proposed closure plan for such impoundments must be submitted as soon as practicable, but no later than December 31, 2016. At a minimum, (i) impoundments located in whole above the seasonal high groundwater table shall be dewatered; (ii) impoundments located in whole or in part beneath the seasonal high groundwater table shall be dewatered to the maximum extent practicable; and (iii) the owner of an impoundment shall either:

a. Convert the coal combustion residuals impoundment to an industrial landfill by removing all coal combustion residuals and contaminated soil from the impoundment temporarily, safely storing the residuals on-site, and complying with the requirements for such landfills established by this Article and rules adopted thereunder. At a minimum, the landfills shall have a design with a leachate collection system, a closure cap system, and a composite liner system consisting of two components: the upper component shall consist of a minimum 30-ml flexible membrane (FML), and the lower components shall consist of at least a two-foot layer of compacted soil with a hydraulic conductivity of no more than 1×10^{-7} centimeters per second. FML components consisting of high density polyethylene (HDPE) shall be at least 60 ml thick. The landfill shall otherwise comply with the construction requirements established by

Section .1624 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code, and the siting and design requirements for disposal sites established by Section .0503 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code, except with respect to those requirements that pertain to buffers. In lieu of the buffer requirement established by Section .0503(f)(2)(iii) of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code, the owner of the impoundment shall establish and maintain a 300-foot buffer between surface waters and disposal areas. After the temporarily displaced coal combustion residuals have been returned for disposal in the industrial landfill constructed pursuant to the requirements of this sub-subdivision, the owner of the landfill shall comply with the closure and post-closure requirements established by Section .1627 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code. A landfill constructed pursuant to this sub-subdivision shall otherwise be subject to all applicable requirements of this Chapter and rules adopted thereunder. Prior to closure, the Department may allow the disposal of coal combustion residuals, in addition to those originally contained in the impoundment, to the landfill constructed pursuant to this sub-subdivision, if the Department determines that the site is suitable for additional capacity and that disposal of additional coal combustion residuals will not pose an unacceptable risk to public health, safety, welfare; the environment; and natural resources.

b. Remove all coal combustion residuals from the impoundment, return the former impoundment to a nonerosive and stable condition and (i) transfer the coal combustion residuals for disposal in a coal combustion residuals landfill, industrial landfill, or municipal solid waste landfill or (ii) use the coal combustion products in a structural fill or other beneficial use as allowed by law. The use of coal combustion products (i) as structural fill shall be conducted in accordance with the requirements of Subpart 3 of this Part and (ii) for other beneficial uses shall be conducted in accordance with the requirements of Section .1700 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code (Requirements for Beneficial Use of Coal Combustion By-Products) and Section .1205 of Subchapter T of Chapter 2 of Title 15A of the North Carolina Administrative Code (Coal Combustion Products Management).

(2) Intermediate-risk impoundments shall be closed as soon as practicable, but no later than December 31, 2024. A proposed closure plan for such impoundments must be submitted as soon as practicable, but no later than December 31, ~~2017.~~2019. At a minimum, such impoundments shall be dewatered, and the owner of an impoundment shall close the impoundment in any manner allowed pursuant to subdivision (1) of this ~~subsection.~~subsection, or, if applicable, as provided in G.S. 130A-309.216.

(3) Low-risk impoundments shall be closed as soon as practicable, but no later than December 31, 2029. A proposed closure plan for such impoundments must be submitted as soon as practicable, but no later than December 31, ~~2018.~~2019. At a minimum, (i) impoundments located in whole above the seasonal high groundwater table shall be dewatered; (ii) impoundments located in whole or in part beneath the seasonal high groundwater table shall be dewatered to the maximum extent practicable; and (iii) at the election of the Department, the owner of an impoundment shall either:

a. Close in any manner allowed pursuant to subdivision (1) of this ~~subsection.~~subsection;

b. Comply with the closure and post-closure requirements established by Section .1627 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code, except that such impoundments shall not be required to install and maintain a leachate collection system. Specifically, the owner of an impoundment shall install and maintain a cap system that is designed to minimize infiltration and erosion in conformance with the requirements of Section .1624 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code, and, at a minimum, shall be designed and constructed to (i) have a permeability no greater than 1×10^{-5} centimeters per second; (ii) minimize infiltration by the use of a low-permeability barrier that contains a minimum 18 inches of earthen material; and (iii) minimize erosion of the cap system and protect the low-permeability barrier from root penetration by use of an erosion layer that contains a minimum of six inches of earthen material that is capable of sustaining native plant growth. In addition, the owner of an impoundment shall (i) install and maintain a groundwater monitoring system; (ii) establish financial assurance that will ensure that sufficient funds are available for closure pursuant to this subdivision, post-closure maintenance and monitoring, any corrective action that the Department may require, and satisfy any potential liability for sudden and nonsudden accidental occurrences arising from the impoundment and subsequent costs incurred by the Department in response to an incident, even if the owner becomes insolvent or ceases to reside, be incorporated, do business, or maintain assets in the State; and (iii) conduct post-closure care for a period of 30 years, which period may be increased by the Department upon a determination that a longer period is necessary to protect public health, safety, welfare; the environment; and natural resources, or decreased upon a determination that a shorter period is sufficient to protect public health, safety, welfare; the environment; and natural resources. The Department may require implementation of any other measure it deems necessary to protect public health, safety, and welfare; the environment; and natural resources, including imposition of institutional controls that are sufficient to protect public health, safety, and welfare; the environment; and natural resources. The Department may not approve closure for an impoundment pursuant to sub-subdivision b. of subdivision (3) of this subsection unless the Department finds that the proposed closure plan includes design measures to prevent, upon the plan's full implementation, post-closure exceedances of groundwater quality standards beyond the compliance boundary that are attributable to constituents associated with the presence of the ~~impoundment.~~impoundment; or

c. Comply with the closure requirements established by the United States Environmental Protection Agency as provided in 40 CFR Parts 257 and 261, "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities."

(4) Closure Plans for all impoundments shall include all of the following:

a. Facility and coal combustion residuals surface impoundment description. – A description of the operation of the site that shall include, at a minimum, all of the following:

1. Site history and history of site operations, including details on the manner in which coal combustion residuals have been stored and disposed of historically.
2. Estimated volume of material contained in the impoundment.
3. Analysis of the structural integrity of dikes or dams associated with impoundment.
4. All sources of discharge into the impoundment, including volume and characteristics of each discharge.
5. Whether the impoundment is lined, and, if so, the composition thereof.

6. A summary of all information available concerning the impoundment as a result of inspections and monitoring conducted pursuant to this Part and otherwise available.

b. Site maps, which, at a minimum, illustrate all of the following:

1. All structures associated with the operation of any coal combustion residuals surface impoundment located on the site. For purposes of this sub-subdivision, the term "site" means the land or waters within the property boundary of the applicable electric generating station.
2. All current and former coal combustion residuals disposal and storage areas on the site, including details concerning coal combustion residuals produced historically by the electric generating station and disposed of through transfer to structural fills.
3. The property boundary for the applicable site, including established compliance boundaries within the site.
4. All potential receptors within 2,640 feet from established compliance boundaries.
5. Topographic contour intervals of the site shall be selected to enable an accurate representation of site features and terrain and in most cases should be less than 20-foot intervals.
6. Locations of all sanitary landfills permitted pursuant to this Article on the site that are actively receiving waste or are closed, as well as the established compliance boundaries and components of associated groundwater and surface water monitoring systems.
7. All existing and proposed groundwater monitoring wells associated with any coal combustion residuals surface impoundment on the site.
8. All existing and proposed surface water sample collection locations associated with any coal combustion residuals surface impoundment on the site.

c. The results of a hydrogeologic, geologic, and geotechnical investigation of the site, including, at a minimum, all of the following:

1. A description of the hydrogeology and geology of the site.
2. A description of the stratigraphy of the geologic units underlying each coal combustion residuals surface impoundment located on the site.
3. The saturated hydraulic conductivity for (i) the coal combustion residuals within any coal combustion residuals surface impoundment located on the site and (ii) the saturated hydraulic conductivity of any existing liner installed at an impoundment, if any.
4. The geotechnical properties for (i) the coal combustion residuals within any coal combustion residuals surface impoundment located on the site, (ii) the geotechnical properties of any existing liner installed at an impoundment, if any, and (iii) the uppermost identified stratigraphic unit underlying the impoundment, including the soil classification based upon the Unified Soil Classification System, in-place moisture content, particle size distribution, Atterberg limits, specific gravity, effective friction angle, maximum dry density, optimum moisture content, and permeability.
5. A chemical analysis of the coal combustion residuals surface impoundment, including water, coal combustion residuals, and coal combustion residuals-affected soil.
6. Identification of all substances with concentrations determined to be in excess of the groundwater quality

standards for the substance established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code, including all laboratory results for these analyses.

7. Summary tables of historical records of groundwater sampling results.
8. A map that illustrates the potentiometric contours and flow directions for all identified aquifers underlying impoundments (shallow, intermediate, and deep) and the horizontal extent of areas where groundwater quality standards established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code for a substance are exceeded.
9. Cross-sections that illustrate the following: the vertical and horizontal extent of the coal combustion residuals within an impoundment; stratigraphy of the geologic units underlying an impoundment; and the vertical extent of areas where groundwater quality standards established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code for a substance are exceeded.

d. The results of groundwater modeling of the site that shall include, at a minimum, all of the following:

1. An account of the design of the proposed Closure Plan that is based on the site hydrogeologic conceptual model developed and includes (i) predictions on post-closure groundwater elevations and groundwater flow directions and velocities, including the effects on and from the potential receptors and (ii) predictions at the compliance boundary for substances with concentrations determined to be in excess of the groundwater quality standards for the substance established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code.
2. Predictions that include the effects on the groundwater chemistry and should describe migration, concentration, mobilization, and fate for substances with concentrations determined to be in excess of the groundwater quality standards for the substance established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code pre- and post-closure, including the effects on and from potential receptors.
3. A description of the groundwater trend analysis methods used to demonstrate compliance with groundwater quality standards for the substance established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code and requirements for corrective action of groundwater contamination established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code.

e. A description of any plans for beneficial use of the coal combustion residuals in compliance with the requirements of Section .1700 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code (Requirements for Beneficial Use of Coal Combustion By-Products) and Section .1205 of Subchapter T of Chapter 2 of Title 15A of the North Carolina Administrative Code (Coal Combustion Products Management).

f. All engineering drawings, schematics, and specifications for the proposed Closure Plan. If required by Chapter 89C of the General Statutes, engineering design documents should be prepared, signed, and sealed by a professional engineer.

g. A description of the construction quality assurance and quality control program to be implemented in conjunction with the Closure

Plan, including the responsibilities and authorities for monitoring and testing activities, sampling strategies, and reporting requirements.

h. A description of the provisions for disposal of wastewater and management of stormwater and the plan for obtaining all required permits.

i. A description of the provisions for the final disposition of the coal combustion residuals. If the coal combustion residuals are to be removed, the owner must identify (i) the location and permit number for the coal combustion residuals landfills, industrial landfills, or municipal solid waste landfills in which the coal combustion residuals will be disposed and (ii) in the case where the coal combustion residuals are planned for beneficial use, the location and manner in which the residuals will be temporarily stored. If the coal combustion residuals are to be left in the impoundment, the owner must (i) in the case of closure pursuant to sub-subdivision (a)(1)a. of this section, provide a description of how the ash will be stabilized prior to completion of closure in accordance with closure and post-closure requirements established by Section .1627 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code and (ii) in the case of closure pursuant to sub-subdivision (a)(1)b. of this section, provide a description of how the ash will be stabilized pre- and post-closure. If the coal combustion residuals are to be left in the impoundment, the owner must provide an estimate of the volume of coal combustion residuals remaining.

j. A list of all permits that will need to be acquired or modified to complete closure activities.

k. A description of the plan for post-closure monitoring and care for an impoundment for a minimum of 30 years. The length of the post-closure care period may be (i) proposed to be decreased or the frequency and parameter list modified if the owner demonstrates that the reduced period or modifications are sufficient to protect public health, safety, and welfare; the environment; and natural resources and (ii) increased by the Department at the end of the post-closure monitoring and care period if there are statistically significant increasing groundwater quality trends or if contaminant concentrations have not decreased to a level protective of public health, safety, and welfare; the environment; and natural resources. If the owner determines that the post-closure care monitoring and care period is no longer needed and the Department agrees, the owner shall provide a certification, signed and sealed by a professional engineer, verifying that post-closure monitoring and care has been completed in accordance with the post-closure plan. If required by Chapter 89C of the General Statutes, the proposed plan for post-closure monitoring and care should be signed and sealed by a professional engineer. The plan shall include, at a minimum, all of the following:

1. A demonstration of the long-term control of all leachate, affected groundwater, and stormwater.
2. A description of a groundwater monitoring program that includes (i) post-closure groundwater monitoring, including parameters to be sampled and sampling schedules; (ii) any additional monitoring well installations, including a map with the proposed locations and well construction details; and (iii) the actions proposed to mitigate statistically significant increasing groundwater quality trends.

l. An estimate of the milestone dates for all activities related to closure and post-closure.

m. Projected costs of assessment, corrective action, closure, and post-closure care for each coal combustion residuals surface impoundment.

n. A description of the anticipated future use of the site and the necessity for the implementation of institutional controls following closure, including property use restrictions, and requirements for recordation of notices documenting the presence of contamination, if applicable, or historical site use.

(b) The Department shall review a proposed Coal Combustion Residuals Surface Impoundment Closure Plan for consistency with the minimum requirements set forth in subsection (a) of this section and whether the proposed Closure Plan is protective of public health, safety, and welfare; the environment; and natural resources and otherwise complies with the requirements of this Part. Prior to issuing a decision on a proposed Closure Plan, the Department shall provide for public participation on the proposed Closure Plan as follows:

(1) The Department shall make copies of the proposed Closure Plan available for inspection as follows:

a. A copy of the proposed Closure Plan shall be provided to the local health director.

b. A copy of the proposed Closure Plan shall be provided to the public library located in closest proximity to the site in the county or counties in which the site is located.

c. The Department shall post a copy of the proposed Closure Plan on the Department's Web site.

d. The Department shall place copies of the declaration in other locations so as to assure the reasonable availability thereof to the public.

(2) Before approving a proposed Closure Plan, the Department shall give notice as follows:

a. A notice and summary of the proposed Closure Plan shall be published weekly for a period of three consecutive weeks in a newspaper having general circulation in the county or counties where the site is located.

b. Notice that a proposed Closure Plan has been developed shall be given by first-class mail to persons who have requested such notice. Such notice shall include a summary of the proposed Closure Plan and state the locations where a copy of the proposed Closure Plan is available for inspection. The Department shall maintain a mailing list of persons who request notice pursuant to this section.

c. Notice that a proposed Closure Plan has been developed shall be given by electronic mail to persons who have requested such notice. Such notice shall include a summary of the proposed Closure Plan and state the locations where a copy of the proposed Closure Plan is available for inspection. The Department shall maintain a mailing list of persons who request notice pursuant to this section.

(3) No later than 60 days after receipt of a proposed Closure Plan, the Department shall conduct a public meeting in the county or counties in which the site is located to explain the proposed Closure Plan and alternatives to the public. The Department shall give notice of the hearing at least 30 days prior to the date thereof by all of the following methods:

a. Publication as provided in subdivision (1) of this subsection, with first publication to occur not less than 30 days prior to the scheduled date of the hearing.

b. First-class mail to persons who have requested notice as provided in subdivision (2) of this subsection.

c. Electronic mail to persons who have requested notice as provided in subdivision (2) of this subsection.

(4) At least 30 days from the latest date on which notice is provided pursuant to subdivision (2) of this subsection shall be allowed for the receipt of written comment on the proposed Closure Plan prior to its approval. At least 20 days

will be allowed for receipt of written comment following a hearing conducted pursuant to subdivision (3) of this subsection prior to the approval of the proposed Closure Plan.

(c) The Department shall disapprove a proposed Coal Combustion Residuals Surface Impoundment Closure Plan unless the Department finds that the Closure Plan is protective of public health, safety, and welfare; the environment; and natural resources and otherwise complies with the requirements of this Part. The Department shall provide specific findings to support its decision to approve or disapprove a proposed Closure Plan. If the Department disapproves a proposed Closure Plan, the person who submitted the Closure Plan may seek review as provided in Article 3 of Chapter 150B of the General Statutes. If the Department fails to approve or disapprove a proposed Closure Plan within 120 days after a complete Closure Plan has been submitted, the person who submitted the proposed Closure Plan may treat the Closure Plan as having been disapproved at the end of that time period. The Department may require a person who proposes a Closure Plan to supply any additional information necessary for the Department to approve or disapprove the Closure Plan.

~~(d) Within 30 days of its approval of a Coal Combustion Residuals Surface Impoundment Closure Plan, the Department shall submit the Closure Plan to the Coal Ash Management Commission. The Commission shall evaluate all information submitted in accordance with this Part related to the Closure Plan and any other information the Commission deems relevant. The Commission shall approve the Closure Plan if it determines that the Closure Plan was developed in accordance with this section, that implementation of the Closure Plan according to the Closure Plan's schedule is technologically and economically feasible, and the Closure Plan is protective of the public health, safety, and welfare; the environment; and natural resources. In addition, the Commission may consider any impact on electricity costs and reliability, but this factor may not be dispositive of the Commission's determination. The Commission shall issue its determination in writing, including findings in support of its determination. If the Commission fails to act on a Closure Plan within 60 days of receipt of the Closure Plan, the Closure Plan shall be deemed approved. Parties aggrieved by a final decision of the Commission pursuant to this subsection may appeal the decision as provided under Article 3 of Chapter 150B of the General Statutes.~~

(e) As soon as practicable, but no later than 60 days after a Coal Combustion Residuals Surface Impoundment Closure Plan has been approved by the ~~Coal Ash Management Commission,~~Department, the owner of the coal combustion residuals impoundment shall begin implementation of the approved plan. Modifications to an approved Closure Plan may only be allowed in conformance with the requirements of this Part, upon written request of an owner of an impoundment, with the written approval of the Department, and after public notice of the change in accordance with the requirements of subdivision (2) of subsection (b) of this section. Provided, however, minor technical modifications may be made in accordance with standard Department procedures for such minor modifications and may be made without written approval of the Department or public notice of the change.

(f) Nothing in this section shall be construed to obviate the need for sampling, remediation, and monitoring activities at the site as required by G.S. 130A-309.211 and G.S. 130A-309.310 [G.S. 130A-309.212].

"**§ 130A-309.215. Variance authority.**

(a) In recognition of the complexity and magnitude of the issues surrounding the management of coal combustion residuals and coal combustion residuals surface impoundments, the General Assembly authorizes the ~~Commission~~ Secretary to grant a variance to extend any deadline ~~for closure of an impoundment established under G.S. 130A-309.214 in conformance with the requirements of this section. To request such a variance the owner of an impoundment~~ under this act, on the Secretary's own motion, or that of an impoundment owner, on the basis that compliance with the deadline cannot be achieved by application of best available technology found to be economically reasonable at the time and would produce serious hardship without equal or greater benefits to the public.

(a1) For variances requested by an impoundment owner, the owner shall, no earlier than ~~two years~~one year prior to the applicable deadline, submit an application in a form acceptable to the Department which shall include, at a minimum, all of the following information: identification of the site, applicable requirements, and applicable deadlines for which a variance is sought, and the site-specific circumstances that support the need for the variance. The owner of the impoundment shall also provide detailed information that demonstrates (i) the owner has substantially complied with all other requirements and deadlines established by this Part; (ii) the owner has made good faith efforts to comply with the applicable deadline for closure of the impoundment; and (iii) that compliance with the deadline cannot be achieved by application of best available technology found to be economically reasonable at the time and would produce serious hardship without equal or greater benefits to the public. As soon as practicable, but no later than 60 days from receipt of an application, the Secretary shall evaluate the information submitted in conjunction with the application, and any other information the Secretary deems relevant, to determine whether the information supports issuance of a variance. ~~After such evaluation, if the Secretary finds that the information supports issuance of a variance from the deadline, the Secretary shall issue a proposed variance. Within 10 days after a proposed variance has been issued, the Secretary shall issue a written declaration, including findings of fact, documenting the proposed variance.~~

(a2) The Department shall provide for public participation on ~~the~~a proposed variance in the manner provided by G.S. 130A-309.214(b) and shall take the public input received through the process into account in its decision concerning ~~the proposed~~issuance of a variance. ~~Within 30 days of the receipt of all public input received, the Department shall submit a proposed variance to the Coal Ash Management Commission. The Commission shall evaluate all information submitted in accordance with this section and any other information the Commission deems relevant.~~ The ~~Commission~~ Department shall only approve a variance if it determines that compliance with the deadline cannot be achieved by application of best available technology found to be economically reasonable at the time and would produce serious hardship without equal or greater benefits to the public. The ~~Commission~~ Department shall issue its determination in writing, including findings in support of its determination. If the ~~Commission~~ Department fails to act on a variance request within 60 days of receipt, the variance shall be deemed denied.

(a3) Parties aggrieved by a final decision of the Commission pursuant to this subsection may appeal the decision as provided under Article 3 of Chapter 150B of the General Statutes.

~~(b) A variance granted pursuant to this section shall not extend a deadline for closure of an impoundment more than three years beyond the date applicable to the impoundment as provided under G.S. 130A-309.214.~~

~~(c) No more than one variance may be granted pursuant to this section per impoundment.~~

"§ 130A-309.216. Ash beneficiation projects.

(a) On or before January 1, 2017, an impoundment owner shall (i) identify, at a minimum, impoundments at two sites located within the State with ash stored in the impoundments on that date that is suitable for processing for cementitious purposes and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundment(s) located at the sites. As soon as legally practicable thereafter, the impoundment owner shall apply for all permits necessary for the ash beneficiation projects from the Department. The Department shall expedite any State permits and approvals required for such projects. No later than 24 months after issuance of all necessary permits, operation of both ash beneficiation projects shall be commenced. An impoundment owner shall use commercially reasonable efforts to produce 300,000 tons of ash to specifications appropriate for cementitious products from each project.

(b) On or before July 1, 2017, an impoundment owner shall (i) identify an impoundment at an additional site located within the State with ash stored in the impoundment on that date that is suitable for processing for cementitious purposes and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundment(s) located at the site. As soon as legally practicable thereafter, the impoundment owner shall apply for all permits necessary for the ash beneficiation project from the Department. The Department shall expedite any State permits and approvals required for such projects. No later than 24 months after issuance of all necessary permits, operation of the ash beneficiation project shall be commenced. An impoundment owner shall use commercially reasonable efforts to produce 300,000 tons of ash to specifications appropriate for cementitious products from the project.

(c) Notwithstanding any deadline for closure provided by G.S. 130A-309.214, any impoundment classified as intermediate- or low-risk that is located at a site at which an ash beneficiation project is installed, operating, and processing at least 300,000 tons of ash annually from the impoundment, shall be closed no later than December 31, 2029.

"**§ 130A-309.217: Reserved for future codification purposes.**"

SECTION 2. G.S. 62-302.1 reads as rewritten:

"**§ 62-302.1. Regulatory fee for combustion residuals surface impoundments.**

(a) Fee Imposed. – Each public utility with a coal combustion residuals surface impoundment shall pay a regulatory fee for the purpose of defraying the costs of oversight of coal combustion residuals. The fee is in addition to the fee imposed under G.S. 62-302. The fees collected under this section shall only be used to pay the expenses of the ~~Coal Ash Management Commission and the~~ Department of Environmental Quality in providing oversight of coal combustion residuals.

(b) Rate. – The combustion residuals surface impoundment fee shall be ~~three-hundredths of one percent (0.03%)~~ twenty-two thousandths of one percent (0.022%) of the North Carolina jurisdictional revenues of each public utility with a coal combustion residuals surface impoundment. For the purposes of this section, the term "North Carolina jurisdictional revenues" has the same meaning as in G.S. 62-302.

(c) When Due. – The fee shall be paid in quarterly installments. The fee is payable to the ~~Coal Ash Management Commission~~ Department of Environmental Quality on or before the 15th of the second month following the end of each quarter. Each public utility subject to this fee shall, on or before the date the fee is due for each quarter, prepare and render a report on a form prescribed by the ~~Coal Ash Management Commission.~~ Department of Environmental Quality. The report shall state the public utility's total North Carolina jurisdictional revenues for the preceding quarter and shall be accompanied by any supporting documentation that the ~~Coal Ash Management Commission~~Department of Environmental Quality may by rule require. Receipts shall be reported on an accrual basis.

(d) Use of Proceeds. – A special fund in the ~~Office of State Treasurer and the Coal Ash Management Commission~~ Department of Environmental Quality is created. The fees collected pursuant to this section ~~and all other funds received by the Coal Ash Management Commission~~ shall be deposited in the Coal Combustion Residuals Management Fund. The Fund shall be placed in an interest-bearing account, and any interest or other income derived from the Fund shall be credited to the Fund. Subject to appropriation by the General Assembly, ~~twenty-six and one-half percent (26.5%) of the moneys in the Fund shall be used by the Coal Ash Management Commission and the remainder~~ one hundred percent (100%) shall be used by the Department of Environmental Quality. ~~The Coal Ash Management Commission shall be subject to the provisions of the State Budget Act, except that no unexpended surplus of the Coal Combustion Residuals Management Fund shall revert to the General Fund.~~ All funds credited to the Fund shall be used only to pay the expenses of the ~~Coal Ash Management Commission and the~~ Department of Environmental Quality in providing oversight of coal combustion residuals.

(e) Recovery of Fee. – The North Carolina Utilities Commission shall not allow an electric public utility to recover this fee from the retail electric customers of the State."

SECTION 3.(a) Notwithstanding G.S. 130A-309.213 or G.S. 130A-309.214, as amended by Section 1 of this act, and except as otherwise preempted by the requirements of federal law, the following coal combustion residuals surface impoundments shall be deemed intermediate-risk and, as soon as practicable, but no later than August 1, 2028, shall be closed in conformance with Section 3(b) of this act:

(1) Coal combustion residuals surface impoundments located at the H.F. Lee Steam Station, owned and operated by Duke Energy Progress, and located in Wayne County.

(2) Coal combustion residuals surface impoundments located at the Cape Fear Steam Station, owned and operated by Duke Energy Progress, and located in Chatham County.

(3) Coal combustion residuals surface impoundments located at the Weatherspoon Steam Station, owned and operated by Duke Energy Progress, and located in New Hanover County.

SECTION 3.(b) The impoundments identified in subsection (a) of this section shall be closed as follows:

(1) Impoundments located in whole above the seasonal high groundwater table shall be dewatered. Impoundments located in whole or in part beneath the

seasonal high groundwater table shall be dewatered to the maximum extent practicable.

(2) All coal combustion residuals shall be removed from the impoundments and transferred for (i) disposal in a coal combustion residuals landfill, industrial landfill, or municipal solid waste landfill or (ii) use in a structural fill or other beneficial use as allowed by law. The use of coal combustion products (i) as structural fill shall be conducted in accordance with the requirements of Subpart 3 of Part 2I of Article 9 of the General Statutes and (ii) for other beneficial uses shall be conducted in accordance with the requirements of Section .1700 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code (Requirements for Beneficial Use of Coal Combustion By-Products) and Section .1200 of Subchapter T of Chapter 2 of Title 15A of the North Carolina Administrative Code (Coal Combustion Products Management), as applicable.

(3) If restoration of groundwater quality is degraded as a result of the impoundment, corrective action to restore groundwater quality shall be implemented by the owner or operator as provided in G.S. 130A-309.211.

SECTION 4. There is appropriated a sum of up to four hundred fifty thousand dollars ($450,000) to the State Water Infrastructure Authority from the Coal Combustion Residuals Management Fund cash balance on June 30, 2016, to fund grants to local governments operating public water supplies in areas surrounding coal combustion residuals impoundments to provide moneys for additional staff for permitting and construction activities as may be needed to facilitate establishment of permanent water supplies to households eligible for connection to public water supplies pursuant to G.S. 130A-309.211(c1).

SECTION 5.(a) Section 3(e) of S.L. 2014-122 is repealed.

SECTION 5.(b) Section 4(e) of S.L. 2014-122 reads as rewritten:

"**SECTION 4.(e)** All electric generating facilities owned by a public utility that produce coal combustion residuals and coal combustion products shall issue a request for proposals on or before December 31, 2014, for (i) the conduct of a market analysis for the concrete industry and other industries that might beneficially use coal combustion residuals and coal combustion products; (ii) the study of the feasibility and advisability of installation of technology to convert existing and newly generated coal combustion residuals to commercial-grade coal combustion products suitable for use in the concrete industry and other industries that might beneficially use coal combustion residuals; and (iii) an examination of all innovative technologies that might be applied to diminish, recycle or reuse, or mitigate the impact of existing and newly generated coal combustion residuals. All electric generating facilities shall present the materials and information received in response to a request for proposals issued pursuant to this section and an assessment of the materials and information, including a forecast of specific actions to be taken in response to the materials and information received, to the Environmental Management Commission ~~and the Coal Ash Management Commission~~ on or before August 1, 2016."

SECTION 6.(a) G.S. 143B-291 reads as rewritten:

"**§ 143B-291. North Carolina Mining Commission – members; selection; removal; compensation; quorum; services.**

(a) Repealed by 2014-4, s. 5(a), effective July 31, 2015.

(a1) Members, Selection. – The North Carolina Mining Commission shall consist of eight members appointed as follows:

(1) One member who is the chair of the North Carolina State University Minerals Research Laboratory Advisory ~~Committee.~~<u>Committee, ex officio and nonvoting.</u>

(2) The State Geologist, ex officio and nonvoting.

(3) One member appointed by the Governor <u>subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution,</u> who is a representative of the mining industry.

(4) One member appointed by the Governor <u>subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution,</u> who is a representative of the mining industry.

(5) One member appointed by the ~~General Assembly upon recommendation of the Speaker of the House of Representatives~~ <u>Governor subject to</u>

confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who is a representative of the mining industry.

(6) One member appointed by the ~~General Assembly upon recommendation of the President Pro Tempore of the Senate~~ Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who is a representative of the mining industry.

(7) One member appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in conformance with G.S. 120-121, who is a ~~member of~~ representative of a nongovernmental conservation ~~interests.~~interest.

(8) One member appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in conformance with G.S. 120-121, who is a ~~member of~~representative of a nongovernmental conservation ~~interests.~~interest.

(a2) Process for Appointments by the Governor. – The Governor shall transmit to the presiding officers of the Senate and the House of Representatives, within four weeks of the convening of the session of the General Assembly in the year for which the terms in question are to expire, the names of the persons to be appointed by the Governor and submitted to the General Assembly for confirmation by joint resolution. If an appointment is required pursuant to this subsection when the General Assembly is not in session, the member may be appointed and serve on an interim basis pending confirmation by the General Assembly. For the purpose of this subsection, the General Assembly is not in session only (i) prior to convening of the regular session, (ii) during any adjournment of the regular session for more than 10 days, or (iii) after sine die adjournment of the regular session.

(b) Terms. – The term of office of a member of the Commission is ~~six years.~~four years, beginning effective January 1 of the year of appointment and terminating on December 31 of the year of expiration. At the expiration of each member's term, the appointing authority shall replace the member with a new member of like qualifications for a term of ~~six~~ four years. ~~The term of the member appointed under subdivision (5) of subsection (a1) of this section shall expire on June 30 of years that precede by one year those years that are evenly divisible by six. The term of members appointed under subdivisions (3) and (6) of subsection (a1) of this section shall expire on June 30 of years that follow by one year those years that are evenly divisible by six. The term of members appointed under subdivisions (4) and (7) of subsection (a1) of this section shall expire on June 30 of years that follow by three years those years that are evenly divisible by six. Upon the expiration of a six-year term, a member may continue to serve until a successor is appointed and duly qualified as provided by G.S. 128-7.~~In order to establish regularly overlapping terms, initial appointments shall be made effective June 1, 2016, or as soon as feasible thereafter, and expire as follows:

(1) The initial appointments made by the Governor:

a. Pursuant to subdivision (a1)(3) of this section shall expire December 31, 2020.

b. Pursuant to subdivision (a1)(4) of this section shall expire December 31, 2020.

c. Pursuant to subdivision (a1)(5) of this section shall expire December 31, 2019.

d. Pursuant to subdivision (a1)(6) of this section shall expire December 31, 2019.

(2) The initial appointment made by the General Assembly upon recommendation of the Speaker of the House of Representatives pursuant to subdivision (a1)(7) of this section shall expire December 31, 2018.

(3) The initial appointment made by the General Assembly upon recommendation of the President Pro Tempore of the Senate pursuant to subdivision (a1)(8) of this section shall expire December 31, 2018.

(c) Vacancies. – In case of death, incapacity, resignation, or vacancy for any other reason in the office of any member appointed by the Governor, prior to the expiration of the member's term of office, the name of the successor shall be submitted by the Governor within four weeks after the vacancy arises to the General Assembly for confirmation by the General Assembly. In case of death, incapacity, resignation, or vacancy for any other reason in the office of any member appointed by the General Assembly, vacancies in those appointments shall be filled in accordance with G.S. 120-122. If a vacancy arises or exists when the General Assembly is not in session, and the appointment is deemed urgent by the Governor, the member may be appointed by the Governor and serve on an interim basis pending confirmation or appointment by the General Assembly, as applicable. An appointment to fill a vacancy shall be for the unexpired balance of the term.

(d) Removal. – The Governor may remove any member of the Commission from office for misfeasance, malfeasance, or nonfeasance in accordance with the provisions of ~~G.S. 143B-13.~~ G.S. 143B-13, or for good cause.

(e) Compensation. – The members of the Commission shall receive per diem and necessary traveling and subsistence expenses in accordance with the provisions of G.S. 138-5.

(f) Quorum. – A majority of the Commission shall constitute a quorum for the transaction of business.

(g) Staff. – All clerical and other services required by the Commission shall be supplied by the Secretary of Environmental ~~Quality.~~Quality. The Commission staff shall be housed in the Department of Environmental Quality and supervised by the Secretary of Environmental Quality."

SECTION 6.(b) Notwithstanding the provisions of G.S. 143B-291(a2) and G.S. 143B-291(b), as enacted and amended by Section 6(a) of this act, initial appointments made by the Governor to the Commission shall not require confirmation by the General Assembly.

SECTION 7.(a) G.S. 143B-293.2 reads as rewritten:

"**§ 143B-293.2. North Carolina Oil and Gas Commission – members; selection; removal; compensation; quorum; services.**

(a) Repealed by Session Laws 2014-4, s. 4(a), effective July 31, 2015.

(a1) Members Selection. – The North Carolina Oil and Gas Commission shall consist of nine members appointed as follows:

(1) One appointed by the ~~General Assembly upon recommendation of the Speaker of the House of Representatives~~ Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who, at the time of initial appointment, is an elected official of a municipal government located in a region of North Carolina that has oil and gas potential. A person serving in this seat may complete a term on the Commission even if the person is no longer serving as an elected official of a municipal government but may not be reappointed to a subsequent term.

(2) One appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in conformance with G.S. 120-121, who shall be a geologist with experience in oil and gas exploration and development.

(3) One appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in conformance with G.S. 120-121, who is a ~~member~~ representative of a nongovernmental conservation interest.

(4) One appointed by the ~~General Assembly upon recommendation of the President Pro Tempore of the Senate~~ Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who, at the time of initial appointment, is a member of a county board of commissioners of a county located in a region of North Carolina that has oil and gas potential. A person serving in this seat may complete a term on the Commission even if the person is no longer serving as county commissioner but may not be reappointed to a subsequent term.

(5) One appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in conformance with G.S. 120-121, who is a ~~member~~representative of a nongovernmental conservation interest.

(6) One appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in conformance with G.S. 120-121, who shall be an engineer with experience in oil and gas exploration and development.

(7) One appointed by the Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who shall be a representative of a publicly traded natural gas company.

(8) One appointed by the Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who shall be a licensed attorney with experience in legal matters associated with oil and gas exploration and development.

(9) One appointed by the Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, with experience in matters related to public health.

(a2) Process for Appointments by the Governor. – The Governor shall transmit to the presiding officers of the Senate and the House of Representatives, within four weeks of the convening of the session of the General Assembly in the year for which the terms in question are to expire, the names of the persons to be appointed by the Governor and submitted to the General Assembly for confirmation by joint resolution. If an appointment is required pursuant to this subsection when the General Assembly is not in session, the member may be appointed and serve on an interim basis pending confirmation by the General Assembly. For the purpose of this subsection, the General Assembly is not in session only (i) prior to convening of the regular session, (ii) during any adjournment of the regular session for more than 10 days, or (iii) after sine die adjournment of the regular session.

(b) Terms. – The term of office of members of the Commission is ~~three years.~~four years, beginning effective January 1 of the year of appointment and terminating on December 31 of the year of expiration. A member may be reappointed to no more than two consecutive ~~three-year~~four-year terms. The term of a member who no longer meets the qualifications of their respective appointment, as set forth in subsection ~~(a)~~(a1) of this section, shall terminate but the member may continue to serve until a new member who meets the qualifications is appointed.~~ The terms of members appointed under subdivisions (1), (4), and (7) of subsection (a1) of this section shall expire on June 30 of years evenly divisible by three. The terms of members appointed under subdivisions (2), (5), and (8) of subsection (a1) of this section shall expire on June 30 of years that precede by one year those years that are evenly divisible by three. The terms of members appointed under subdivisions (3), (6), and (9) of subsection (a1) of this section shall expire on June 30 of years that follow by one year those years that are evenly divisible by three.~~ In order to establish regularly overlapping terms, initial appointments shall be made effective June 1, 2016, or as soon as feasible thereafter, and expire as follows:

(1) The initial appointments made by the Governor:
- a. Pursuant to subdivision (a1)(1) of this section shall expire December 31, 2020.
- b. Pursuant to subdivision (a1)(4) of this section shall expire December 31, 2020.
- c. Pursuant to subdivision (a1)(7) of this section shall expire December 31, 2020.
- d. Pursuant to subdivision (a1)(8) of this section shall expire December 31, 2019.
- e. Pursuant to subdivision (a1)(9) of this section shall expire December 31, 2019.

(2) The initial appointments made by the General Assembly upon recommendation of the Speaker of the House of Representatives:
- a. Pursuant to subdivision (a1)(2) of this section shall expire December 31, 2018.
- b. Pursuant to subdivision (a1)(3) of this section shall expire December 31, 2019.

(3) The initial appointments made by the General Assembly upon recommendation of the President Pro Tempore of the Senate:
- a. Pursuant to subdivision (a1)(5) of this section shall expire December 31, 2018.
- b. Pursuant to subdivision (a1)(6) of this section shall expire December 31, 2019.

(c) ~~Vacancies; Removal from Office. –~~ Vacancies. – In case of death, incapacity, resignation, or vacancy for any other reason in the office of any member appointed by the Governor, prior to the expiration of the member's term of office, the name of the successor shall be submitted by the Governor within four weeks after the vacancy arises to the General Assembly for confirmation by the General Assembly. In case of death, incapacity, resignation, or vacancy for any other reason in the office of any member appointed by the General Assembly, vacancies in those appointments shall be filled in conformance with G.S. 120-122. If a vacancy arises or exists when the General Assembly is not in session and the appointment is deemed urgent by the Governor, the member may be appointed by the Governor and serve on an interim basis pending confirmation or appointment by the General Assembly, as applicable. An appointment to fill a vacancy shall be for the unexpired balance of the term.

(c1) Removal. –

~~(1)~~ ~~Any appointment by the Governor to fill a vacancy on the Commission created by the resignation, dismissal, death, or disability of a member shall be for the balance of the unexpired term.~~ The Governor shall have the power to remove any member of the Commission from office for misfeasance, malfeasance, or nonfeasance in accordance with the provisions of G.S. 143B-13 of the Executive Organization Act of ~~1973.~~1973, or for good cause.

~~(2)~~ ~~Members appointed by the President Pro Tempore of the Senate and the Speaker of the House of Representatives shall be made in accordance with G.S. 120-121, and vacancies in those appointments shall be filled in accordance with G.S. 120-122. In accordance with Section 10 of Article VI of the North Carolina Constitution, a member may continue to serve until a successor is duly appointed.~~

(d) Compensation. – The members of the Commission shall receive per diem and necessary traveling and subsistence expenses in accordance with the provisions of G.S. 138-5.

(e) Quorum. – A majority of the Commission shall constitute a quorum for the transaction of business.

(f) Staff. – All staff support required by the Commission shall be supplied by the Division of Energy, Mineral, and Land Resources and the North Carolina Geological ~~Survey.~~ Survey, and supervised by the Secretary of Environmental Quality.

(g) Committees. – In addition to the Committee on Civil Penalty Remissions required to be established under G.S. 143B-293.6, the chair may establish other committees from members of the Commission to address specific issues as appropriate. No member of a committee may hear or vote on any matter in which the member has an economic interest. A majority of a committee shall constitute a quorum for the transaction of business.

(h) Office May Be Held Concurrently With Others. – Membership on the Oil and Gas Commission is hereby declared to be an office that may be held concurrently with other elective or appointive offices in addition to the maximum number of offices permitted to be held by one person under G.S. 128-1.1."

SECTION 7.(b) Notwithstanding the provisions of G.S. 143B-293.2(a1) and G.S. 143B-293.2(b), as enacted and amended by Section 7(a) of this act, initial appointments made by the Governor to the Commission shall not require confirmation by the General Assembly.

SECTION 7.(c) For purposes of the rules set forth in 15A NCAC 05H (Oil and Gas Conservation Rules), modifications made to the Oil and Gas Commission under Section 7(a) of this act shall, pursuant to G.S. 150B-21.7, be construed to (1) have repealed authority to adopt such rules given to previously constituted commissions and (2) transferred the authority to adopt such rules to the Oil and Gas Commission as modified by Section 7(b) of this act. Therefore, pursuant to G.S. 150B-21.7, rules set forth in 15A NCAC 05H (Oil and Gas Conservation Rules) shall be effective until the Oil and Gas Commission, as modified Section 7(a) of this act, amends or repeals the rules.

SECTION 8. The provisions of this act shall be severable, and if any phrase, clause, sentence, or provision is declared to be unconstitutional or otherwise invalid, the validity of the remainder of this act shall not be affected thereby.

SECTION 9. Except as otherwise provided, this act is effective when it becomes law. Requirements for establishment of a permanent alternative water supply under G.S. 130A-309.211(c1), as enacted by Section 1 of this act, shall apply only to households with drinking water supply wells in existence on the date this act becomes effective.

In the General Assembly read three times and ratified this the 1st day of July, 2016.

s/ Philip E. Berger
President Pro Tempore of the Senate

s/ Tim Moore
Speaker of the House of Representatives

____
Pat McCrory
Governor

Approved ___________.m. this ________________ day of _____________________, 2016